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BEFORE THE ARIZONA CORPORATION COMMISSION

</div>

Robert "Bob" Burns, Chairman
Boyd Dunn
Sandra D. Kennedy
Justin Olson
Lea Marquez Peterson

IN THE MATTER OF THE APPLICATION OF)
ARIZONA PUBLIC SERVICE COMPANY FOR A)
HEARING TO DETERMINE THE FAIR VALUE OF)
UTILITY PROPERTY OF THE COMPANY FOR)   Docket No. E-01345A-19-0236
RATEMAKING PURPOSES, TO FIX A JUST AND)
REASONABLE RATE OF RETURN THEREON, TO)
APPROVE RATE SCHEDULES DESIGNED TO)
DEVELOP SUCH RETURN)
_____)

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**FEDERAL EXECUTIVE AGENCIES' NOTICE OF FILING SURREBUTTAL
TESTIMONY OF AMANDA M. ALDERSON, MICHAEL P. GORMAN, AND
CHRISTOPHER C. WALTERS**

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The Federal Executive Agencies (FEA) hereby file the Surrebuttal Testimony of Amanda M.

Alderson, Michael P. Gorman, and Christopher C. Walters in the above-captioned docket.

RESPECTFULLY SUBMITTED THIS 4th day of December, 2020.

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I hereby certify that FEA's Surrebuttal Testimony of Amanda M. Alderson, Michael P. Gorman, and Christopher C. Walters was e-filed through the ACC Portal on the 4th day of December, 2020 and 8 paper copies were mailed to:

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Copies of the foregoing were delivered on the 4th day of December, 2020 to each party on the attached service list by electronic or regular mail.

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BEFORE THE

ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN))))))))))))	DOCKET NO. E-01345A-19-0236

Surrebuttal Testimony and Attachment of

Amanda M. Alderson

On behalf of

Federal Executive Agencies

December 4, 2020

BAI

BRUBAKER & ASSOCIATES, INC.

Project 10899

BEFORE THE

ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	))))))))))))	DOCKET NO. E-01345A-19-0236

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Surrebuttal Testimony of Amanda M. Alderson

Attachment AMA-1SR

BEFORE THE

ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-01345A-19-0236

Surrebuttal Testimony of Amanda M. Alderson

1   Q   **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2   A   Amanda M. Alderson. My business address is 16690 Swingley Ridge Road,

3   Suite 140, Chesterfield, MO 63017.

4   Q   **ARE YOU THE SAME AMANDA M. ALDERSON WHO PREVIOUSLY FILED**

5   **TESTIMONY IN THIS PROCEEDING?**

6   A   Yes. On October 9, 2020, I filed Direct Testimony on behalf of the Federal Executive

7   Agencies ("FEA").

8   Q   **WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?**

9   A   I will respond to the Direct Testimony of Staff witness Mr. David Dismukes concerning

10   Staff's Average and Peak ("A&P") production demand allocator proposal, and to the

11   Rebuttal Testimonies of Arizona Public Service Company ("APS" or "Company")

1   witnesses Ms. Jessica Hobbick and Mr. Leland Snook concerning the Company's

2   cost of service study ("COSS") and proposed spread of the revenue increase.

3   My silence in regard to any issue should not be construed as an endorsement

4   of the positions put forth by APS or any intervening party.

I. REBUTTAL TO STAFF

6   **Q   DOES MR. DISMUKES COMMENT ON THE USE OF THE AVERAGE AND**

7   **EXCESS ("A&E") PRODUCTION ALLOCATION METHOD USED BY APS?**

8   A   Yes. Mr. Dismukes rejects the A&E production capacity cost allocation methodology

9   used by APS in this and several previous cases, in favor of the Average and Peak

10   ("A&P") method.[1] He takes this position despite the Commission's express approval

11   of the A&E method over the A&P method in APS's 2007 base rate proceeding.[2]

12   **Q   DOES MR. DISMUKES OFFER NEW EVIDENCE IN SUPPORT OF HIS**

13   **RECOMMENDATION TO REJECT THE A&E IN FAVOR OF THE A&P IN THIS**

14   **PROCEEDING?**

15   A   No. Mr. Dismukes provides no new evidence in this proceeding that supports the use

16   of the A&P method over the A&E method. Mr. Dismukes claims, however, that the

17   arguments against the A&P method raised by AECC in the 2007 proceeding "conflate

18   the concepts of energy and demand and the roles each of these play in utility system

19   planning."[3] In other words, Mr. Dismukes is attempting to rebut evidence and

20   arguments that are not a part of the instant proceeding. AECC has thus far provided

21   no testimony on the A&P method in this proceeding.

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[1] Dismukes Direct Testimony at 2.
[2] Decision No. 69663, pages 69-71.
[3] Dismukes Direct Testimony at 13.

1 Q   **WHAT FURTHER ARGUMENT DOES MR. DISMUKES MAKE AGAINST THE A&E**

2   **METHOD?**

3 A   Mr. Dismukes takes issue with the use of the non-coincident peak ("NCP") to develop

4   the "excess" portion of the A&E allocator development, arguing that production

5   capacity costs are more appropriately allocated using a coincident peak ("CP")

6   allocator as opposed to an NCP allocator. Mr. Dismukes therefore believes that the

7   Commission's prior approval of the A&E NCP allocation method is inappropriate, and

8   should be overturned in favor of the A&P method.[4]

9 Q   **PLEASE RESPOND.**

10 A   Mr. Dismukes' logic is flawed. The mathematical development of the A&E allocation

11   factor must use an NCP to develop the "excess" portion, because using the CP would

12   lead to allocator results that are identical to a demand-only production allocator, as

13   identified in the NARUC Manual,[5] and as identified by Staff itself in the 2015 Tucson

14   Electric rate case.[6] In that proceeding, Staff witness Solganick opposed Tucson

15   Electric's proposed development of the A&E allocators using a 4CP component,

16   accurately indicating that erroneous use of the 4CP component leads to a

17   mathematical result that is identical to a demand-only production allocator. In that

18   proceeding, Staff did not however recommend abandoning the A&E method in favor

19   of the A&P method, as Mr. Dismukes does in this instant proceeding. Instead, Staff

20   recommended correcting the A&E method to use the NCP component instead of the

21   4CP component.[7]

---

[4] *Id.* at 16.
[5] NARUC Manual at 50.
[6] Solganick Direct Testimony in Docket No. E-10933A-15-0322, filed June 24, 2016, at 19.
[7] *Id.* at 20.

1   As correctly reasoned by Staff in its 2016 testimony, use of the NCP in the

2   A&E development does not render the allocation method invalid. On the contrary, the

3   A&E method utilizing the NCP factor is reasonable, and serves to develop just and

4   reasonable retail rates for customers, as determined by this Commission,[8] and

5   several other utility commissions throughout the United States.[9]

6 Q   **WHAT ARE THE PRIMARY FLAWS OF THE A&P METHOD THAT LED THE**

7   **COMMISSION TO REJECT IT IN PRIOR PROCEEDINGS?**

8 A   The Commission expressly cited in Decision No. 69663 the criticism that the A&P

9   method leads to the average demand (i.e., energy) of each class being double-

10   counted.[10] The energy allocator for each class is counted once in the "average"

11   portion of the A&P, and again as a subcomponent of the "peak" portion. The

12   Commission appropriately concluded that the A&E method is superior to the A&P

13   because it resolves this flaw.

14   Further, in that same Decision, the Commission cited FEA's testimony in that

15   proceeding arguing that the A&P method leads to an asymmetrical allocation of

16   production plant and fuel costs, due to the fact that high load factor customers receive

17   an outsized allocation of fixed production costs but not an appropriate offsetting

18   outsized allocation of below-average fuel costs from baseload units.[11] This argument

19   is still relevant today, and is a valid flaw of the A&P method.

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[8]Decision No. 69663 at 70-71.

[9]I am aware of utilities in Colorado, New Mexico and Texas that use Commission-approved A&E allocators.

[10]Decision No. 69663 at 71.

[11]*Id.*

1   Q   **ARE THESE DEFICIENCIES IN THE A&P METHODOLOGY STILL PRESENT IN**

2   **THIS CASE?**

3   A   Yes. Staff's proposed A&P allocation method double-counts the energy allocation

4   attributed to each rate class, and leads to an asymmetrical allocation of production

5   plant and fuel costs.

6   Q   **HAS STAFF PREVIOUSLY SUPPORTED THE A&P METHOD?**

7   A   Yes. In APS's 2007 base rate case, which concluded with Decision No. 69663

8   wherein the Commission rejected the A&P method in favor of the A&E method, Staff

9   proposed the A&P method using class contributions to the utility's 4 CPs to develop

10   the "peak" portion of the A&P. Staff's proposal was termed the "4CP & Average" in

11   that proceeding.

12   Q   **HAS STAFF CONTINUED TO SUPPORT THE A&P METHOD SINCE THE**

13   **COMMISSION'S REJECTION OF THE METHOD IN 2007?**

14   A   Not recently. FEA issued a discovery request seeking a listing of all Staff testimonies

15   filed over the last five years. Staff's response to FEA 2.2 is provided on page 4 of

16   Attachment AMA-1SR. Upon review of these testimonies, it is evident that Staff has

17   not recently supported the A&P method, and in fact has recommended use of the

18   A&E method.[12] Further, Staff is presently supporting the A&E method in the ongoing

19   Tucson Electric proceeding.[13] When asked to explain the apparent discrepancy

20   between Staff's current positions on the A&P and A&E allocation methodology in both

21   the pending Tucson Electric and APS proceedings, Staff briefly replied that "each rate

22   application is independently evaluated," but provided no substantive rationale for its

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[12]Solganick Direct Testimony in Docket No. E-04204A-15-0142, filed December 9, 2015, at 3;
Solganick Direct Testimony in Docket No. E-10933A-15-0322, filed June 24, 2016, at 20.
        [13]Belavadi Direct Testimony in Docket No. E-01933A-19-0028.

1 apparent departure from historical opposition to the A&P method.[14] When asked to

2 provide all analyses Staff conducted in order to develop its revised conclusion that

3 the A&P method is now reasonable, when in several prior cases it has opposed the

4 A&P method or supported the A&E method, it did not provide any analyses.[15]

5 **Q PLEASE SUMMARIZE YOUR RESPONSE TO STAFF'S A&P ALLOCATION**

6 **RECOMMENDATIONS IN THIS PROCEEDING.**

7 A Staff has not provided any substantive evidence that has not already been

8 considered by this Commission on the matter of the use of the A&P method over the

9 A&E method for production cost allocation. Further, Staff has not justified the

10 discrepancy between its proposals in the instant proceeding vis-à-vis the ongoing

11 Tucson Electric proceeding. There is insufficient evidence on the record to justify the

12 Commission finding the A&P method more reasonable than the A&E method that has

13 been approved for Arizona utilities for several years. I recommend the Commission

14 reject Staff's proposal.

15 # II. REBUTTAL TO APS

16 **Q MS. HOBBICK ADDRESSES THE COMPANY'S POSITION, UNCHANGED FROM**

17 **ITS DIRECT TESTIMONIES, SUPPORTING AN EQUAL SPREAD OF THE**

18 **REVENUE INCREASE TO ALL CUSTOMER CLASSES. DO YOU HAVE ANY**

19 **CONCERNS WITH MS. HOBBICK'S REBUTTAL TESTIMONY?**

20 A Yes. Ms. Hobbick claims at page 4 of her rebuttal testimony that significant progress

21 was made in the last rate case to align rates to cost of service, and therefore an equal

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[14]Staff Response to FEA 2.1 (c), provided on page 3 of Attachment AMA-1SR.
[15]Staff Response to FEA 2.3, provided on page 4 of Attachment AMA-1SR.

1   spread of the revenue increase to all classes is appropriate in the instant

2   proceeding.[16]

3   **Q   HOW DO YOU RESPOND?**

4   A   Ms. Hobbick's claim is false. APS's own direct testimony contradicts Ms. Hobbick's

5   claim, as shown in the Direct Testimony of Mr. Leeland Snook, at pages 13-14.

6   Mr. Snook states:

7   The summary and COSS schedules plainly show disparities in : (1) the
8   ratio of the allocated cost for APS to actually provide service; and (2)
9   what customer classes and sub-classes pay for the services APS
10   provides. **The residential class contributes less towards the cost**
11   **to serve than the general service class. Specifically, under**
12   **current rates, the revenue from the residential class covers**
13   **approximately 85% of the cost to serve, while the general class**
14   **covers 107% of the cost to serve. <u>However, APS is not proposing</u>**
15   **<u>to rebalance revenue responsibility in this rate case based on the</u>**
16   **<u>results</u>.**[17]

17   Ms. Hobbick suggests that because the approved rate increase for residential

18   customers in the last base rate case was 4.54%, while the approved increase for the

19   general service class was 1.87%, then out of fairness the revenue increase should be

20   spread equally to all classes in this proceeding.[18]

21   However, an equal spread would be contrary to APS's own COSS results, and

22   would allow for the subsidies between rate classes that APS itself admits exist, to

23   continue unchecked. While movement toward cost-based rates was set in motion in

24   the last proceeding, assigning a larger share of the increase in that case to the

25   classes further from cost, the results of the Company's own COSS in this case show

26   that further movement is still necessary.

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[16]Hobbick Rebuttal Testimony at 4.
[17]Snook Direct Testimony at 13-14 (emphasis added).
[18]Hobbick Rebuttal Testimony at 4.

1 Q MS. HOBBICK DOES NOT AGREE WITH YOUR PROPOSAL OUTLINED IN YOUR

2 DIRECT TESTIMONY TO SPREAD THE REVENUE INCREASE MORE IN LINE

3 WITH COSS RESULTS.[19] HOW DO YOU RESPOND?

4 A Ms. Hobbick indicates that my proposal would allocate a larger proportion of the

5 overall requested increase to the residential class than to the general service class.

6 Ms. Hobbick neglects to address the rationale for my proposed unequal spread of the

7 revenue increase, which is to align the spread with COSS results. This is further

8 evidence that the Company's proposed revenue spread in this proceeding ignores the

9 goal of creating cost-based, just and reasonable rates.

10 Q REGARDING COST ALLOCATION WITHIN THE COSS, DID COMPANY WITNESS

11 MR. SNOOK ADDRESS STAFF'S PROPOSED A&P PRODUCTION DEMAND

12 ALLOCATOR?

13 A Yes. Mr. Snook states that Staff has not provided sufficient support to move away

14 from the long-standing and widely-approved A&E allocation methodology in this case,

15 noting that the A&E method has been approved by the Commission without objection

16 in the last three APS rate cases, and is the method currently used by both Tucson

17 Electric and UNS Electric. [20]

18 Q. HOW DO YOU RESPOND?

19 A Mr. Snook provides a well-reasoned rebuttal to Staff's proposed A&P allocation

20 method, and I support the Company's position on this issue.

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[19] *Id.* at 6.
[20] Snook Rebuttal Testimony, page 28-30.

1 **Q** **DID MR. SNOOK ADDRESS YOUR PROPOSAL TO ALLOCATE THE CAPACITY**

2 **VALUE OF RENEWABLE AND NON-RENEWABLE PURCHASED POWER**

3 **EXPENSE AS A DEMAND-RELATED COST?**

4 **A** Yes. Mr. Snook states that the allocation change is valid, however he contends that

5 there are "little to no capacity costs inherent in current purchased power costs," and

6 therefore APS supports evaluating this issue in the context of the next base rate

7 case, but not the instant proceeding.[21] Further, Mr. Snook contends that "because

8 APS is recommending a proportional allocation of the requested increase

9 **irrespective of the COSS results**,"[22] then it makes no difference whether this valid

10 cost allocation correction is made in this proceeding

11 **Q** **HOW DO YOU RESPOND?**

12 **A** First, as evidenced in my Direct Testimony, $67.8 million, or 15%, of test year fuel

13 and purchased power expense, are capacity payments for non-renewable purchased

14 capacity.[23] I estimate an additional $57.0 million are capacity-related costs of

15 renewable purchased power expense.[24] These values represent approximately 40%

16 of fuel and purchased power expense in the test year, and APS's proposal to

17 incorrectly allocate these costs does have a meaningful impact on COSS results.

18 Table 2 of my Direct Testimony shows the approximately $10 million shift in cost

19 allocation between rate classes after appropriately classifying these amounts as

20 demand-related costs.

21 To Mr. Snook's second point on the immateriality of the COSS in this

22 proceeding, I disagree. I maintain that the approved spread of the revenue increase

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[21] *Id.* at 30.
[22] Snook Rebuttal Testimony at 30, (emphasis added).
[23] Alderson Direct Testimony at 10.
[24] *Id.* at 13.

1   should be grounded in proper COSS results in order to develop just and reasonable,

2   cost-based rates, and therefore the Commission should approve my proposal.

3   Q   **DID MR. SNOOK ALSO ADDRESS YOUR PROPOSAL TO APPROPRIATELY**

4   **CLASSIFY CERTAIN DISTRIBUTION-RELATED COSTS AS CUSTOMER-**

5   **RELATED?**

6   A   Yes.   Mr. Snook agrees that it is appropriate and cost-based to classify certain

7   distribution-related costs as customer-related because the cost of this distribution

8   infrastructure does not vary with customers' demand or energy usage.   But

9   nevertheless he again declines to develop an appropriate COSS because APS is not

10   supporting cost-based rates in this proceeding.[25]

11   Specifically, Mr. Snook describes several types of distribution costs that do not

12   vary with the customer's peak demand or monthly energy usage, and therefore may

13   be more reasonably classified as customer-related costs, and admits that APS has

14   supported this classification in its last general rate case.

15   Q   **PLEASE RESPOND**

16   A   It is concerning that APS admits to deficiencies in its COSS, deficiencies that bias the

17   study and render the results flawed.   However, it is more concerning that APS

18   believes the policy preference to equally spread the revenue increase to all rate

19   classes renders moot the need to determine the appropriate cost of service revenue

20   requirement for each rate class. The Commission cannot make an informed decision

21   on how best to establish just and reasonable rates, with clear pricing signals to all

---

[25] *Id.* at 32-33.

1   ratepayers, without an accurate understanding of the revenue subsidies and

2   inefficiencies currently present in APS's rate structure.

3   Again, I strongly recommend that the Commission instruct APS to develop its

4   COSS following my recommended allocation adjustment proposals, in order to

5   ascertain the most reasonable estimate of the cost to serve each customer class. If

6   the Commission ultimately determines that policy preferences support an equal

7   spread of the revenue to all rate classes, it can be fully informed of the relative levels

8   of subsidies that may exist between each rate class.

9   ## III. RESPONSE REGARDING AG-X / AG-Y PROGRAM

10   Q   **HAVE YOU REVIEWED THE PARTIES' DIRECT TESTIMONY AND THE**

11   **COMPANY'S REBUTTAL TESTIMONY REGARDING THE AG-X AND AG-Y**

12   **PROGRAM?**

13   A   Yes. AECC, Kroger, Calpine, Direct Energy, and Staff all address the AG-X and/or

14   AG-Y programs. AECC, Kroger, Calpine, and Direct Energy opine that the AG-Y

15   program does not provide sufficient customer benefit as it does not permit customers

16   to contract for a competitive cost for power supply with a third-party provider, and

17   does not provide capacity cost credits for the provision of that power.[26] I generally

18   agree with the sentiment that the value proposition for retail ratepayers is significantly

19   diminished under APS's proposed Rate AG-Y program as compared to the existing

20   Rate AG-X. I agree with the intervenors' conclusions that the AG-Y program does not

21   permit a customer to hedge, or otherwise manage, its power supply costs, but instead

22   requires the customer to pay hourly index energy charges to APS. Such a volatile

23   pricing structure increases market price risk to subscribers, whereas the AG-X

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[26]Higgins Direct at 34, Baron Direct at 24-25, Bass Direct at 15-16.

1   program allows for mitigation of price risk through bilateral agreements with third-

2   party providers.

3   The Company's rebuttal testimony continues to support, unchanged, its novel

4   Rate AG-Y program and declines to expand the Rate AG-X program. Company

5   witnesses claim that Rate AG-X customers are not providing firm, non-interruptible

6   capacity through their third-party contractual arrangements,[27] and that the pricing

7   structure of the Rate AG-X program does not fully cover the costs to serve these

8   customers.[28] APS does not quantify the claimed shortfall revenue of the current Rate

9   AG-X program, nor is it recommending any changes to the program in this

10   proceeding.

11 Q **HAVE THE PARTIES' TESTIMONIES CAUSED YOU TO ALTER YOUR POSITION**

12   **ON THE RATE AG-Y PROPOSAL YOU ADVOCATED IN YOUR DIRECT**

13   **TESTIMONY?**

14 A No. I continue to suggest that the Rate AG-Y program be available to customers that

15   have previously applied to the Rate AG-X program but were not selected through the

16   lottery process. Certain customers may be willing to accept increased price volatility

17   if they feel they can effectively manage their own customer hourly loads in order to

18   strive for cost reductions. Both large and medium business customers should be

19   provided such an option, if it would be economically beneficial for them. These varied

20   types of price offerings are an important tool in creating overall average rate decline

21   for APS retail customers as a whole, which is the aim of Commissioner Peterson's

22   correspondence from November 17, 2020, which I will address more fully in the next

23   section of my testimony.

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[27]Albert Rebuttal at 27-28.
[28]Snook Rebuttal at 23.

1   ## IV. RESPONSE TO COMMISSIONER PETERSON'S CORRESPONDENCE

2   **Q   HAVE YOU REVIEWED THE NOVEMBER 17, 2020 CORRESPONDENCE FROM**

3   **COMMISSIONER LEA MÁRQUEZ PETERSON TO THE INTERESTED PARTIES IN**

4   **THIS PROCEEDING?**

5   A   Yes.   The correspondence requests that parties work together to achieve a rate

6   decrease for APS ratepayers, and to address a number of potential avenues by which

7   such a rate decrease might be achieved. I have restated below the list as provided

8   by the Commissioner, and have provided after each one my suggestions on the

9   issue.

10   1.   *Reducing costs to consumers by focusing on customer growth, improving*
11   *customer retention, and attracting new businesses to APS's service*
12   *territory, including rate designs and amounts that help to attract new*
13   *customers and spur economic development.*

14   One major tool to attract new businesses to APS's service territory and
15   improve large customer retention is to assess to all customers just and
16   reasonable rates that do not promote subsidies between rate classes.
17   Using an appropriate COSS to develop those just and reasonable rates is
18   imperative, not least to identify the subsidies that exist between classes,
19   then also to enact rate changes to eliminate those subsidies. In my direct
20   testimony, I have supported the Company's proposed production and
21   transmission fixed plant cost allocation. I have recommended corrections
22   to the classification and allocation of certain variable purchased power
23   costs, and distribution plant costs.   In this surrebuttal testimony, I also
24   oppose Staff's proposed reversion of the erroneous A&P production cost
25   allocation methodology. Designing rates that align with cost of service
26   and reducing subsidies paid by large use and high load factor customers
27   will certainly serve to attract new business to the APS service territory.

28   2.   *Reducing costs to consumers by exploring new and innovative rate*
29   *designs, such as value-based pricing, critical peak pricing, risk-sharing,*
30   *market-based pricing, and other rate options.*

31   New rate designs can be an effective way to incent customers to make
32   more efficient use of utility system resources, which will lead to a decline
33   in the overall system cost of power for all customers. I will provide an
34   example of the impact on system average power cost of efficient use of
35   the utility system resource at the conclusion of this list of items. Provided
36   that new and innovative rate designs are rooted in cost causation, such
37   offerings can serve to reduce overall system costs. It is imperative that
38   these nontraditional rate designs be rooted in cost of service, because

1   subsidies will be created if the rate design does not provide for adequate
2   cost recovery of the true cost of service.   For example, APS's own
3   testimony in this case shows that small behind-the-meter rooftop solar
4   customers are being subsidized by other ratepayers, due to the fact that
5   customers do not provide full cost recovery for the fixed distribution plant
6   needed to serve them.[29] Certain solar industry intervenors are seeking to
7   reduce the rates paid by behind-the-meter rooftop solar customers,[30]
8   which would serve to exacerbate the existing subsidies. These types of
9   arguments make clear how important it is to establish an accurate cost-
10   based rate at the outset of a novel rate design offering, and provide clear
11   price signals to ratepayers of true value of the novel rate design.

12   3.   *Reducing costs to consumers by proactively adapting to market*
13   *conditions, reallocating risk, and taking advantage of historically low*
14   *interest rates or costs of capital.*

15   My colleague, Mr. Christopher Walters, will address this item in his
16   surrebuttal testimony.

17   4.   *Reducing costs to consumers by aggressively pursuing cost savings with*
18   *vendors and suppliers and operating as a leaner and more efficient*
19   *company.*

20   My colleague, Mr. Michael Gorman, will address this item in his
21   surrebuttal testimony.

22   5.   *Reducing costs to consumers by exploring the securitization of all*
23   *generating assets.*

24   My colleague, Mr. Michael Gorman, will address this item in his
25   surrebuttal testimony.

26   6.   Reducing costs to consumers by eliminating or phasing-out protracted
27   subsidies and surcharges.

28   The first step in eliminating subsidies between rate classes is to identify
29   those subsidies. As previously discussed, the COSS is an integral tool to
30   identifying subsidies, and the COSS must use reasonable and cost-based
31   allocation methods in order to be most effective. The second step is to
32   actively reset rates that reduce those subsidies, and APS is significantly
33   failing on this second step in this proceeding.   As I have previously
34   discussed in this surrebuttal testimony, APS has identified subsidies but
35   is choosing to ignore them, and is making no move to remedy them. This
36   tact will create inefficient pricing signals, increase rates to large use and
37   high-load factor customers, and may drive business from the APS
38   territory.

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[29]Attachment LRS-3DR, page 2.
[30]Lucas Direct at 3-4.

1   7.   *Reducing costs to consumers by reducing peak demand, increasing*
2   *economic capacities, and engaging in off-system sales to the benefit of*
3   *Commission-jurisdictional customers.*

4   The concepts of reducing peak demand and increasing the use of APS's
5   system capacity point to an increase in the efficient use of the utility
6   system. Efficiency in use of the available capacity on the system can be
7   measured through system load factor, which is a metric that evaluates
8   how much of the total peak demand is used on average over a particular
9   time period. Generally the utility-wide system load factor is calculated on
10   an annual basis, and is generated by dividing the total energy use of the
11   system over the year, by the maximum generating capacity multiplied by
12   8,760 hours in the year. The load factor formula can be written as such:

13   total annual energy consumed
14   (coincident peak generating capacity * 8,760)

15   One can surmise that increasing the numerator of this metric will increase
16   the total load factor. I will further show below how increasing the system
17   load factor will reduce system average costs. Designing rates to all
18   customers that provide appropriate pricing signals will lead to efficient use
19   of the utility system, and will increase the utility system load factor, driving
20   down total overall costs.

21   8.   *Reducing costs to consumers by looking for ways to advance new*
22   *technologies, provide customer relief, and assist impacted communities*
23   *without increasing rates on customers.*

24   Again, if these novel rate designs that foster new technologies or assist
25   impacted communities are appropriately cost-based and provide efficient
26   pricing signals, they can help drive down the average utility cost.

27   9.   *Reducing costs to consumers by utilizing performance incentive and*
28   *disincentive mechanisms that are fair, [footnote omitted] granular,*
29   *[footnote omitted] and transparent. [footnote omitted]*

30   I understand performance incentive and disincentive mechanisms to be a
31   form of rate design that elicits certain actions from ratepayers. Again I
32   note, if such programs are cost-based and provide accurate pricing
33   signals to ratepayers, they will lead to more efficient use of the utility
34   system and reduced average utility cost.

35   10. *Lastly, please describe how we can work together to achieve $0.09/kWh*
36   *or, in the alternative, how close to $0.09/kWh we can get if $0.09/kWh is*
37   *not possible, and how long it will take us to get there.*

38   To conclude, I would like to exemplify the impact on average utility costs
39   of an increase in system load factor. Assume the total revenue
40   requirement for APS is $235.0 million for a given Test Year, and in that
41   Test Year, the system load factor is 45%. The average utility rate is
42   approximately 11.9 cents/kWh. If through efficient pricing signals to

1   customers, the load factor of the system is increased to 60%, the average
2   utility cost comes down to below 9 cents/kWh.

TABLE 1

Scenario 1: 45% System Load Factor		
Annual energy usage	1,971,000	MWh
Peak generating capacity	500	MW
System Load Factor	45%	
Total Revenue Reqm't	$ 235,000,000	
Average Utility Rate ¢/kWh	11.9	

Scenario 2: 60% System Load Factor		
Annual energy usage	2,628,000	MWh
Peak generating capacity	500	MW
System Load Factor	60%	
Total Revenue Reqm't	$ 235,000,000	
Average Utility Rate ¢/kWh	8.9	

3   Developing cost-based prices will encourage customers to make
4   economic consumption decisions based on the efficient and economic
5   cost of providing utility service. Encouraging economic consumption
6   decisions can lead to greater utilization of the utility infrastructure
7   capacity, encouraging customers to increase energy consumption without
8   increasing the peak demand, which will lead to an improved system load
9   factor and an overall system cost reduction on a per-kwh unit basis. In
10   addition, cost-based pricing can encourage customers to maintain their
11   energy consumption while reducing peak demand, which frees up
12   generating capacity for the utility to sell or retire, which would reduce
13   costs.

14 **Q**   **DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?**

15 A   Yes, it does.

Data Request Responses Supporting the
Surrebuttal Testimony of FEA Witness Amanda M. Alderson

<u>**Page**</u>

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES
TO FEDERAL EXECUTIVE AGENCIES' ("FEA")
SECOND SET OF DATA REQUESTS TO COMMISSION STAFF
DOCKET NO. E-01345A-19-0236
NOVEMBER 18, 2020

FEA 2.1   Please respond to the following regarding Staff's recommendation in this proceeding that retail production demand costs be allocated using an Average and Peak method.

a.   Please confirm or deny that it is Staff's position that the proposed Average and Excess allocation method does not reflect a fair and reasonable approximation of the relative costs to service customers. If so denied, please explain.

RESPONSE:

a.   **Confirm in Part. Dr. Dismukes does not believe that the A&E method represents an appropriate cost allocation method for APS and provided the rationale for this position at page 13 line 2 through page 18 line 7 of his Direct Testimony. Dr. Dismukes can neither confirm nor deny that the A&E cost allocation method represents a "fair" cost allocation to all "customers" since some customers clearly benefit from this method and other clearly do not benefit from this method: fairness, thus, will in large part be relative to the specific customer class which has not be clarified in this interrogatory.**

The A&E method over-weights demand considerations relative to other customer classes, and can thus lead to erroneous results. Dr. Dismukes discusses these logical errors at page 14 line 6 to line 21 of his Direct Testimony which can be illustrated by a simple hypothetical example. Assume a hypothetical electric system without surplus capacity (i.e. the utility's operating reserve margins equal its required margins to ensure reliable operations). Further assume that a new industrial customer with a 100 percent load factor (i.e. the customer requires the same electricity load at all hours of the year) is added to the system, which requires the utility to construct a new generation facility. The A&E cost allocation method assumes that this new industrial customer incurs no capacity-related costs on the utility system since the customer has a 100 percent load factor. The A&E cost allocation method effectively assumes that existing customers, and not the new industrial customer, are the reason for the utility's need to construct a new generation facility by mathematically assigning costs associated with the new generation facility to the industrial customer based on its relative contribution to annual energy requirements on the system. However, as the utility in this hypothetical example required the construction of an additional generation facility to

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES
TO FEDERAL EXECUTIVE AGENCIES' ("FEA")
SECOND SET OF DATA REQUESTS TO COMMISSION STAFF
DOCKET NO. E-01345A-19-0236
NOVEMBER 18, 2020

serve the load of the new industrial customer. As explained by Dr. Dismukes in his testimony, a utility considers the needs of its system on a total basis, ensuring that it has sufficient resources to supply its customers during peak demand periods and sufficient baseload generation resources to supply its customers with relatively inexpensive energy during base demand periods. All customers on a utility system contribute to both of these system requirements.

RESPONDENT: David E. Dismukes, Acadian Consulting Group, 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana 70808.

b. Please provide all analyses conducted by Staff that supports Staff's recommendation and proposals regarding retail production demand cost allocation in this proceeding, in native format, with all formulae and links intact.

RESPONSE:

b. Please see the following files Staff previously provided in response to APS 1.2 and 2.4.

Exhibit DED-1 Comparison of Class Revenue Responsibilities using A&E Method and A&P – 4CP_FINAL.xlsx
Exhibit DED-3 Comparison of Class Revenue Responsibilities using All Adjustments_FINAL.xlsx
WP – Development of Average and Peak based on 4CP_FINAL.xlsx
WP – Alternative COSS (Production Plant Only – A&P 4CP)_FINAL.xlsx
WP – Alternative COSS (All Adjustments)_FINAL.xlsx

RESPONDENT: David E. Dismukes, Acadian Consulting Group, 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana 70808.

c. Please explain the apparent discrepancy between Staff's position regarding production fixed cost allocation methodology in the instant proceeding with Staff's position regarding the same in Tucson Electric Power's ongoing base rate proceeding, described in the Direct Testimony of Gurudatta Belavadi in Docket No. E-01933A-19-0028.

RESPONSE: c. Each rate case application is independently evaluated.

RESPONDENTS: Ranelle Paladino and Barbara Keene, Utilities Division, Arizona Corporation Commission, 1200 W. Washington, Phoenix, Arizona 85007.

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES
TO FEDERAL EXECUTIVE AGENCIES' ("FEA")
SECOND SET OF DATA REQUESTS TO COMMISSION STAFF
DOCKET NO. E-01345A-19-0236
NOVEMBER 18, 2020

d.   Please provide all analyses conducted by Staff in Docket No. E-01933A-19-0028 that supports Staff's recommendation and proposals regarding retail production fixed cost allocation in that proceeding, in native format, with all formulae and links intact.

RESPONSE: **d.**   **Each rate case application is independently evaluated.**

RESPONDENTS: **Ranelle Paladino and Barbara Keene, Utilities Division, Arizona Corporation Commission, 1200 W. Washington, Phoenix, Arizona 85007.**

FEA 2.2   Please provide a list of all testimonies filed by Staff between the period January 1, 2015 and October 30, 2020 that address allocation of retail production fixed costs and/or retail distribution fixed costs. As part of the responsive list, please provide the docket number, witness name, and date of filing.

RESPONSE:

Staff objects to FEA 2.2 as unduly burdensome. FEA asks the Commission to research and compile information for FEA which is equally accessible and available to FEA, and to the public, via the Commission's website.

Without waiving the foregoing objection, Staff provides the following examples:

UNS Electric, Inc.	**E-04204A-15-0142**	**Howard Solganick**	**12/9/2015**
Tucson Electric Power Company	**E-01933A-15-0322**	**Howard Solganick**	**6/24/2016**

RESPONDENT: **Ranelle Paladino and Barbara Keene, Utilities Division, Arizona Corporation Commission, 1200 W. Washington, Phoenix, Arizona 85007.**

FEA 2.3   Please provide a complete explanation along with all supporting analyses of why Staff's position on a production fixed cost allocator is different in this case than it was in the cases listed in response to FEA-Staff 2.2 above.

RESPONSE: **See Response to FEA 2.1 (c) above.**

RESPONDENT: **Ranelle Paladino and Barbara Keene, Utilities Division, Arizona Corporation Commission, 1200 W. Washington, Phoenix, Arizona 85007.**

BEFORE THE

ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	))))))))))))) **DOCKET NO. E-01345A-19-0236**

Surrebuttal Testimony and Attachment of

Michael P. Gorman

On behalf of

Federal Executive Agencies

December 4, 2020

BAI

BRUBAKER & ASSOCIATES, INC.

Project 10899

BEFORE THE

ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	)))))))))))))

DOCKET NO.
E-01345A-19-0236

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Surrebuttal Testimony of Michael P. Gorman

Attachment MPG-1SR

BEFORE THE

ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	)))))))))))))

DOCKET NO.
E-01345A-19-0236

Surrebuttal Testimony of Michael P. Gorman

1   Q   PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

2   A   Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140,

3   Chesterfield, MO 63017.

4   Q   ARE YOU THE SAME MICHAEL P. GORMAN WHO PREVIOUSLY FILED

5   TESTIMONY IN THIS PROCEEDING?

6   A   Yes. On October 2, 2020, I filed Direct Testimony on behalf of the Federal Executive

7   Agencies ("FEA").

8   Q   WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

9   A   I will respond to the Arizona Public Service Company ("APS" or "Company")

10   witnesses' Rebuttal Testimony. These include APS witness Leland R. Snook on my

11   recommendation to disallow the Ocotillo Modernization Project ("OMP") deferred

12   costs and APS witness Elizabeth A. Blankenship on including a regulatory pension

1   asset in rate base, and I will also respond to the Company's proposed Advanced

2   Energy Mechanism ("AEM") that replaces the Formula Rate Proposal the Company is

3   no longer pursuing.

4   Finally, I will respond to Commissioner Lea Márquez Peterson's

5   November 17, 2020 comments related to regulatory practices that would be favorable

6   to the Company, the state's regulatory climate, and to customers. The objective is to

7   reduce the Company's embedded cost of service to around $0.09/kWh, while still

8   positively supporting the Company's financial integrity, regulatory climate, and ability

9   to recover costs.

10   My silence in regard to any issue should not be construed as an endorsement

11   of APS's position.

12   **Q   PLEASE SUMMARIZE YOUR SURREBUTTAL TESTIMONY.**

13   A   In my Direct Testimony, I described how APS's claimed revenue deficiency of

14   $184 million was overstated by at least $128.3 million. In this testimony, I address

15   the APS witnesses' criticisms of my adjustments to the Company's cost of service.

16   Specifically:

17   • Mr. Snook objects to my recommendation that the OMP deferred costs be
18   excluded from APS's cost of service. The Company did not justify including
19   the deferred costs in prospective rates because the Company did not
20   demonstrate that revenue collections during the deferral period were
21   inadequate to support expensing the deferrals. Instead, Mr. Snook's
22   justification for including the deferred costs in prospective rates relies on
23   comparing APS's earned return on equity during a period where only 10% of
24   the deferred costs occurred to APS's last authorized return on equity, which is
25   well above current market costs. I continue to recommend these OMP
26   deferrals be removed from APS's cost of service. This reduces APS's claimed
27   revenue deficiency by $15.6 million.[1]

28   • Mr. Snook also objects to my alternative recommendation that the OMP
29   deferral be recovered on a levelized basis at the Company's embedded cost

---

[1]Attachment MPG-1SR, Page 1, Column 6, Line 2.

1   of debt if the Commission allows APS to recover some level of the OMP
2   deferral. As discussed below, my alternative recommendation is a
3   compromise that strikes a reasonable balance between the utility and its
4   customers when considering how to address the non-traditional costs at issue
5   in this proceeding. My alternative recommendation would reduce the
6   Company's claimed revenue requirement by approximately $4.5 million.[2]

7   •   Ms. Blankenship rejects my recommendation to remove the Company's
8   pension asset from cost of service and instead argues the pension asset
9   should be approved by the Commission regardless of how it is funded.
10   Ms. Blankenship's argument is inconsistent with standard ratemaking
11   practices. Investors are not entitled to an additional return on the pension
12   asset, as Ms. Blankenship believes, because the asset does not represent a
13   cost or an investment by the Company that is funded by investor capital. As
14   noted in my Direct Testimony, investors already earn a return on the pension
15   asset through the increase to the Company's overall rate of return.
16   Ms. Blankenship's proposal to increase the Company's cost of service through
17   both an increase to its rate of return and an increase to its rate base is unjust
18   and unreasonable. Removing the pension asset from the Company's cost of
19   service will lower its claimed revenue deficiency by $42.4 million.[3]

20   In addition, I respond to the Company's new clean energy adjustor

21   mechanism that is presented by APS witnesses Leland Snook, Jeffrey Guldner, and

22   Elizabeth Blankenship. As described in more detail below, the Company did not

23   demonstrate a need for the new adjustor mechanism.

24   Finally, I respond to the November 17, 2020 comments from Commissioner

25   Lea Márquez Peterson regarding how to achieve a rate decrease for APS and its

26   customers and whether the Commission should consider securitization bonds for

27   abandoned plant costs. I believe the objective of more competitive rates can be

28   achieved in this proceeding if the Commission approves cost-based rates with

29   efficient price signals that reflect a reasonable cost of utility service, which provides

30   fair compensation to APS. I also recommend that any use of securitization bonds

31   should consider whether they reduce customers' rates.

---

[2]Attachment MPG-1SR, Page 1, Column 6, Line 2 (APS proposed) less Attachment MPG-1SR, Page 2, Column 6, Line 2 (Gorman rate at cost of debt).

[3]($712.908 million regulatory pension asset - $176.445 million deferred taxes) * 91.80% allocation factor * 8.61% pre-tax ROR on original cost rate base supported by Mr. Walters = $42.4 million.

1 <u>**I. OCOTILLO DEFERRAL**</u>

2 Q **DID THE COMPANY MODIFY ITS OMP DEFERRAL PRO FORMA**

3 **ADJUSTMENTS?**

4 A Yes. The Company updated the deferral with actual costs through September 30,

5 2020, which increased the deferral by $200,000 to approximately $95.1 million. The

6 update impacts the Company's pro forma adjustments to its rate base and income

7 statement.

TABLE 1

<u>**Ocotillo Deferral Reg. Asset**</u>
($ Millions)
(December 31, 2020)

Description	Deferred Costs
Debt Return	$46.4
Property Taxes	$10.6
Depreciation	$33.1
O&M Costs	$4.9
Total	$95.1

Source:
EAB-WP14RB - IS Amortize
Ocotillo Modernization Project
Deferral Update.

8 Q **DID APS WITNESS SNOOK TAKE ISSUE WITH YOUR PROPOSAL TO REMOVE**

9 **THE OMP DEFERRED COSTS FROM APS'S TEST YEAR COST OF SERVICE?**

10 A Yes. Mr. Snook disagrees with my proposal to remove the OMP deferral because the

11 rate revenue during the period the deferral was recorded indicates that APS revenue

12 collections from customers were sufficient to allow it to recover these deferred costs.

1   Mr. Snook argues that APS demonstrated its current rates during the historic

2   test period were not sufficient because the Company earned a return on equity of

3   9.7% during the historic year, which is below its currently authorized return on equity

4   of 10.0%.[4] Mr. Snook also states that had the deferrals been expensed in the historic

5   period, the Company's earned return would have been lower.[5]

6 Q   **IS MR. SNOOK'S PRESENTATION ADEQUATE TO PROVE THAT THE**

7   **REVENUES RECOVERED BY APS IN THE YEAR THE OMP DEFERRALS WERE**

8   **RECORDED WERE NOT SUFFICIENT TO COMPENSATE THE COMPANY FOR**

9   **THESE COSTS?**

10 A   No. Mr. Snook's high-level assessment is simply not proof that the Company should

11   be allowed to include the deferred costs in prospective cost of service. There are

12   several deficiencies in his presentation. First, the question of whether or not the

13   Company should be allowed to include deferred costs for recovery in prospective

14   rates should entail a demonstration that the rate revenue and the earnings in the

15   deferral period were not sufficient. The Company's historical test period is the

16   12-month period ending June 30, 2019. During that period, as shown below in

17   Table 2, the Company only deferred approximately $9.5 million, or roughly 10% of its

18   original requested deferred costs.

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[4]Snook Rebuttal at 6-7.
[5]*Id.* at 7.

TABLE 2

Ocotillo Deferral Reg. Asset
($ Millions)

| Description | Deferred Costs | | | |
	As of 6/30/19	Year Ending 6/30/20	6/30/20 to 12/31/20	Total
Debt Return	$5.3	$27.8	$13.3	$46.4
Property Taxes	$1.2	$6.0	$3.5	$10.6
Depreciation	$3.0	$19.9	$10.2	$33.1
O&M Costs	$0.1	$2.4	$2.5	$4.9
Total	$9.5	$56.1	$29.5	$95.1

Sources:
EAB-WP27DR IS - Ocotillo Deferral Pro Forma.
EAB-WP14RB - IS Amortize Ocotillo Modernization Project Deferral Update.

1   Expensing the amount of deferred costs during the historical period would

2   have reduced the Company's earned return on equity. But APS has not shown

3   whether or not its earned return on equity while expensing these deferred costs would

4   have still provided it fair compensation based on the prevailing capital market cost of

5   equity capital.

6   Just as importantly, as outlined above, significant costs were deferred through

7   year-end 2020. There is no demonstration by the Company that the earnings during

8   this period will not be adequate to provide full recovery of all or part of the deferred

9   OMP costs during this time period. The Company's presentation simply is not

10   adequate to demonstrate that the revenues it collected during the deferral period

11   were not adequate to provide compensation for all, or a significant part, of the OMP

12   deferrals.

13   An up-to-date review of current capital market costs does indicate that APS's

14   last authorized return on equity is well above market. Specifically, my colleague

1   Christopher C. Walters indicates that APS's current authorized return on equity

2   should fall in the range of 9.0% to 9.6%.[6] He recommends a midpoint of 9.3% be

3   used to set APS's rates. Mr. Walters' testimony also shows that authorized returns

4   on equity for integrated electric utility companies have decreased by approximately

5   0.2 percentage points since 2017, APS's last rate case.[7] Further, APS's actual

6   earned return on equity may not reflect the rate of return that would be appropriate for

7   ratemaking purposes if the Company had abnormal expenses that would be

8   normalized or removed in determining whether or not the rates in effect during that

9   time period were sufficient. As such, Mr. Snook's simple observation of the earned

10   return on equity is not consistent with identifying what APS's earnings would be

11   based on regulatory normalization and prudent and reasonable standards that would

12   have been in effect during the deferral period. For all these reasons, Mr. Snook and

13   APS generally have continued to fail to support recovering the OMP deferral in

14   prospective rates. For these reasons, I continue to recommend these OMP deferrals

15   be removed from prospective cost of service.

16   **Q   DID MR. SNOOK RESPOND TO YOUR ALTERNATIVE RECOMMENDATION**

17   **THAT IF THE OMP DEFERRAL IS INCLUDED IN COST OF SERVICE THEN THE**

18   **COSTS SHOULD BE RECOVERED ON A LEVELIZED BASIS AT THE**

19   **COMPANY'S EMBEDDED COST OF DEBT?**

20   A   Yes. Mr. Snook again rejected my alternative recommendation by arguing a debt

21   return only on the OMP deferral is contrary to "normal" regulatory asset treatment and

22   that the deferral should be treated like any other rate base asset.[8]

_____

[6]Walters Direct at 3.
[7]*Id.* at 4 (Figure 1).
[8]Snook Rebuttal at 8.

1   **Q**   **IS USING A DEBT ONLY RETURN CONTRARY TO NORMAL REGULATORY**

2   **ASSET TREATMENT?**

3   **A**   No, not for abandoned plant assets that are not currently being used to provide

4   service, and to which the Commission has not found recovery in prospective rates to

5   be either justified, nor fair and reasonable. Rather, a debt-only return reflects a

6   compromise of costs that were previously incurred when the facility was used and

7   useful in providing service to customers, but due to changes in market conditions the

8   facility is no longer used and useful, and its fair value has been eroded to below its

9   original cost. As such, a reduced carrying charge, along with amortization of the

10   abandoned plant costs, strikes a reasonable balance between the utility and its

11   customers for costs that are no longer used and useful, and have little to no market or

12   fair value. Moreover, the Company's proposal to defer costs that should be

13   recovered currently is contrary to normal accounting practices for ongoing cost of

14   service. As such, both the Company's proposal and my proposal reflect extraordinary

15   regulatory treatment for non-traditional abandoned plant costs.

16   In any event, since APS has failed to prove that all or a significant portion of

17   the deferred costs could not have been fully recovered by the revenues collected

18   during the deferral period based on rates that were in effect, it is appropriate to strike

19   an appropriate balance between the Company and its customers in crafting a

20   treatment for these extraordinary costs.

21   Providing the Company an amortization of the deferred costs, at a nominal

22   carrying charge, strikes a fair compromise for these costs.

1   Q   **WHAT IS THE IMPACT ON THE COMPANY'S REVENUE REQUIREMENT OF**

2   **YOUR ALTERNATIVE TREATMENT BASED ON APS'S UPDATED OMP**

3   **DEFERRAL COSTS?**

4   A   Using the proposed rate of return adjusted for income tax of my associate, Mr.

5   Walters, the Company's proposed treatment of the OMP deferral would result in an

6   annual revenue requirement of approximately $15.7 million in the test year, as shown

7   on Attachment MPG-1SR, page 1.

8   Under a levelized cost recovery, using the cost of debt as the carrying charge,

9   the annual revenue requirement for a ten-year amortization of the updated

10       $95.1 million OMP deferral would be approximately $11.2 million. As such, my

11   alternative recommendation would reduce the Company's claimed revenue

12   requirement by approximately $4.5 million.

13   # II. PENSION ASSET

14   Q   **DID APS WITNESS BLANKENSHIP TAKE ISSUE WITH YOUR PROPOSAL TO**

15   **REMOVE THE COMPANY'S REGULATORY PENSION ASSET FROM RATE**

16   **BASE?**

17   A   Yes. Ms. Blankenship disagrees with my proposal for several reasons. She states at

18   page 14:

19
20
21
22
> First, it is customary for prepayments to be included in rate base, regardless of whether they are prepayments by the utility (increases to rate base) or by its customers (reductions to rate base). There is no reason to treat the net prepayment in this case differently.[9]

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[9]Blankenship Rebuttal at 14.

1   Second, Ms. Blankenship opines that the pension asset should be included in

2   cost of service because customers earn a return (through lower annual pension

3   costs) and therefore Company should also earn a return.[10]

4 Q **PLEASE RESPOND TO MS. BLANKENSHIP'S ASSERTION THAT A**

5   **REGULATORY PENSION ASSET SHOULD BE INCLUDED IN RATE BASE**

6   **REGARDLESS OF HOW IT IS FUNDED.**

7 A Ms. Blankenship's testimony in this regard simply ignores how rates are developed to

8   be balanced and fair to both the Company and to customers.   Contrary to

9   Ms. Blankenship's erroneous testimony, it is standard ratemaking practice to remove

10   an asset from rate base if the asset is funded by collections from customers. For

11   example, in the development of its rate base plant in-service investments, APS

12   reduces its plant in-service investments by removing plant that was funded by

13   "customer advances."   Specifically, the Company reduced its plant in-service rate

14   base investments by $174.4 million of customer advances, in arriving at a net plant

15   investment that is included in the utility's original cost base rate.[11] Plant funded by

16   customers' advances is not included in rate base.

17   Ms. Blankenship's assertion that it does not matter how the asset was funded

18   is simply in direct conflict with standard ratemaking principles, and APS's

19   development of its own rate base in this case. If a utility asset is not funded by

20   investor capital, then the utility is entitled to a rate of return on it, and recovery of the

21   original costs.   On the other hand, if a utility records an asset that is funded by

22   collections from customers, then the utility is not entitled to a rate of return on it. The

23   Company's own filing supports this common sense traditional ratemaking practice.

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[10] *Id.*
[11] Schedule B-1, page 1, line 6.

1   Ms. Blankenship's arguments ignore customer protections and traditional rate-setting

2   practices.

3 **Q**   **IS MS. BLANKENSHIP'S ARGUMENT CONCERNING THE BENEFITS TO**

4   **CUSTOMERS OF THE CREATION OF A REGULATORY PENSION ASSET**

5   **ACCURATE?**

6 A   No. Ms. Blankenship has not demonstrated that the creation of the pension asset

7   has in any way reduced pension expense in this proceeding, and hence the existence

8   of the regulatory pension asset does not produce any customer savings or benefits.

9   Ms. Blankenship's argument is simply without merit.

10   Indeed, as outlined in my Direct Testimony, the Company explained in

11   discovery that the pension asset was created through a non-cash accounting change

12   which was designed to eliminate Other Comprehensive Income ("OCI") from the

13   measurement of common equity capital. Adjusting the OCI balance has the effect of

14   increasing the common equity ratio of total capital, and thus increasing the rate of

15   return. Without including the pension asset in rate base, this accounting change

16   already increases the Company's revenue requirement by approximately $1.2 million,

17   simply by this increasing its rate of return and income tax expense.[12] By also

18   including the regulatory pension asset in rate base, the Company's cost of service

19   would again be increased a second time, and the utility would be provided a return on

20   the regulatory asset twice – once in an increase in overall rate of return and income

21   tax expense (by increasing the equity ratio), and a second time by increasing the

22   original cost rate base.

---

[12]Gorman Direct at 15.

1   The Company's proposal to both increase its cost of service by upwardly

2   adjusting its common equity balance and increasing its rate of return, and to also

3   increase its rate base by a non-cash regulatory asset, is not just and is unreasonable.

4   The creation of the pension asset was not based on an expense or an investment

5   cost to the Company, and this paper pension asset should not be included in rate

6   base. The Company excluding this asset from rate base, but allowing the change in

7   accounting that increases its rate of return, provides the Company reasonable

8   compensation for this accounting change and no further cost of service adjustment is

9   justified.

10   **Q   DO YOU AGREE WITH MS. BLANKENSHIP THAT THE DEVELOPMENT OF THE**

11   **PENSION REGULATORY ASSET WOULD HAVE THE EFFECT OF REDUCING**

12   **THE COMPANY'S PENSION EXPENSE IN THIS PROCEEDING?**

13   A   No. As noted in data responses FEA 5.6[13] and AECC 10.1,[14] the regulatory asset is

14   simply an accounting change by the Company. It is not a "prepaid" pension asset. A

15   prepaid pension asset in contrast to the pension regulatory asset represents funding

16   into the pension trust that is in excess of the pension expense. By funding the

17   pension trust in excess of pension expense, the pension trust assets increase.

18   Creation of a prepaid pension asset could reduce pension expense because of an

19   increased earned return on the pension trust fund assets. The recording of a pension

20   regulatory asset does not change the amount of pension trust fund assets, nor does it

21   increase the expected earned return on the pension trust fund. Hence, in contrast to

22   a prepaid pension asset, pension expense is not impacted by APS recording of a

23   pension regulatory asset. Therefore, Ms. Blankenship's testimony in this regard is

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[13]Previously provided as Attachment MPG-2DR, pages 4-5.
[14]Previously provided as Attachment MPG-2DR, pages 6-7.

1   simply in error. The creation of this pension asset does not reduce pension expense,

2   but it does however increase the Company's rate of return, and potentially its rate

3   base under the Company's proposal. As such, customers would have an increased

4   cost of service with no offset or benefit due to a reduced pension expense under the

5   Company's proposal.

III. PERFORMANCE-BASED RATEMAKING ("PBR")/ADVANCED ENERGY MECHANISM ("AEM")

8   **Q**   **DID APS RESPOND TO THE PARTIES' REQUESTS FOR ITS PILOT PBR**

9   **OFFERED IN ITS DIRECT TESTIMONY?**

10   **A**   Yes. In his Rebuttal Testimony, APS witness Snook states that the Company is no

11   longer requesting a formula rate proposal as part of its rebuttal case. For that reason,

12   he states that APS would not respond to the parties' filed testimony in opposition to

13   this proposal. He did state that while the parties do not support a formula rate

14   mechanism to more closely match revenue recovery with expenses, he does believe

15   there is an opportunity to continue to align interests from a number of parties while

16   providing timely cost recovery of APS's efforts to support a clean energy future.

17   APS is now requesting an Advanced Energy Mechanism ("AEM") rate to

18   recover significant clean energy investments the Company will make to meet its clean

19   energy commitment.[15] Mr. Guldner opines that an AEM mechanism would reduce the

20   frequency of rate cases necessary to recover APS's cost of service, and he believes

21   based on the testimony of APS witness Todd Shipman that the mechanism would be

22   viewed favorably by credit rating agencies as a mechanism that supports the

23   Company's full cost recovery.[16] He also states that the Company will seek the use of

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[15]Rebuttal Testimony of Jeffrey B. Guldner at 6.
[16]*Id.* at 7.

1   securitization bonds to recover retired assets to mitigate the cost of these abandoned

2   plant costs on customers. He concludes that use of securitization bonds and a

3   specialized adjustor mechanism are tools that can reduce rate impacts of

4   transitioning to a clean energy future. Finally, APS witness Barbara Lockwood states

5   at page 25 of her Rebuttal Testimony that the Company continues to support a

6   discussion of PBRs, and notes that the Commission currently has a generic docket

7   open for the role of performance incentive mechanisms and she invites the

8   Commission to consider PBR mechanisms as part of that docket.

9 **Q**   **SHOULD THE COMMISSION APPROVE AN AEM AS PART OF THIS**

10   **PROCEEDING?**

11 **A**   No. While the Company highlights what it perceives to be the benefits of an AEM

12   mechanism to allow for recovery of clean energy investments, it still does not

13   demonstrate a need for an adjustor mechanism. In this proceeding, implementing

14   such a mechanism would not be appropriate and could simply be used to produce

15   excessive costs on customers, and provide unjustified enhancements to the earned

16   rate of return to APS, without adequate Commission oversight and protection of

17   customers. After more details of an approved Commission clean energy environment

18   are known, then the need for a special adjustor mechanism, or the use of traditional

19   base rate mechanisms, can be determined as appropriate to continue to balance the

20   interests of the Company for recovery of reasonable and prudent costs, and

21   customers' need for cost mitigation and competitive rates.

1   **Q**   **MS. LOCKWOOD STATES THAT AN IMPROPERLY-DESIGNED PBR PLAN CAN**

2   **CREATE PERVERSE INCENTIVES. DO YOU BELIEVE PERVERSE INCENTIVES**

3   **CAN WORK FOR OR AGAINST THE COMPANY?**

4   **A**   Yes. Perverse incentives can create regulatory mechanisms that essentially act as

5   pass-through provisions for the utility for making capital investments. Pass-through

6   provisions for adjusting rates to reflect increased invested capital can create the

7   perverse incentive of encouraging the utility to make capital investments in order to

8   increase the PBR, and its profits and ability to increase dividends to its shareholders,

9   rather than make investments that are needed to meet state and federal mandates

10   and to maintain high quality, reliable service. Creating regulatory mechanisms that

11   create economic incentives to encourage companies to grow profits without adding

12   benefits to customers will result in rates that are no longer just and reasonable. This

13   type of PBR would create perverse incentives to the utility to pursue higher profits,

14   irrespective of the impact on customers' rates and the impact on service quality and

15   reliability. Regulatory mechanisms need to maintain an appropriate balance to

16   ensure rates are as competitive as possible to customers, while providing the utility a

17   fair opportunity to earn reasonable profits on investments needed to maintain service

18   quality and reliability, or to meet state and federal environmental mandates.

1 # IV. RESPONSE TO ISSUES SUBMITTED
2 # BY COMMISSIONER LEA MÁRQUEZ PETERSON

3 Q DO YOU HAVE ANY COMMENTS CONCERNING THE ISSUES OUTLINED BY

4 COMMISSIONER LEA MÁRQUEZ PETERSON IN HER NOVEMBER 17, 2020

5 LETTER?

6 A Yes. FEA will respond to the specific issues outlined in this letter in this proceeding.

7 Specific responses will be offered by Amanda M. Alderson, Christopher C. Walters,

8 and me related to these specific issues.

9 Q WHAT ARE THE ISSUES SUBMITTED BY THE COMMISSIONER IN THIS

10 PROCEEDING?

11 A Specific issues the Commissioner requested parties to explore include the following:

12 • Reducing costs to consumers by focusing on customer growth,
13 improving customer retention, and attracting new businesses to
14 APS's service territory, including rate designs and amounts that
15 help to attract new customers and spur economic development;

16 • Reducing costs to consumers by exploring new and innovative rate
17 designs, such as value-based pricing, critical peak pricing, risk-
18 sharing, market-based pricing, and other rate options;

19 • Reducing costs to consumers by proactively adapting to market
20 conditions, reallocating risk, and taking advantage of historically
21 low interest rates or costs of capital;

22 • Reducing costs to consumers by aggressively pursuing cost
23 savings with vendors and suppliers and operating as a leaner and
24 more efficient company;

25 • Reducing costs to consumers by exploring the securitization of all
26 generating assets;

27 • Reducing costs to consumers by eliminating or phasing-out
28 protracted subsidies and surcharges;

29 • Reducing costs to consumers by reducing peak demand,
30 increasing economic capacities, and engaging in off-system sales
31 to the benefit of Commission-jurisdictional customers;

1   • Reducing costs to consumers by looking for ways to advance new
2   technologies, provide customer relief, and assist impacted
3   communities without increasing rates on customers; and

4   • Reducing costs to consumers by utilizing performance incentive
5   and disincentive mechanisms that are fair, [footnote omitted]
6   granular, [footnote omitted] and transparent. [footnote omitted]

7   • Lastly, please describe how we can work together to achieve
8      $0.09/kWh or, in the alternative, how close to $0.09/kWh we can
9   get if $0.09/kWh is not possible, and how long it will take us to get
10   there.

11   **Q   DO YOU HAVE A GENERAL COMMENT ON THE COMMISSIONER'S ISSUES TO**

12   **ACHIEVE MORE COMPETITIVE RATE STRUCTURES FOR ARIZONA**

13   **CUSTOMERS?**

14   A   Yes. I believe it is possible if all parties work together to achieve a more competitive

15   rate structure for APS, while still maintaining APS's financial integrity, access to

16   capital, and providing it reasonable and fair compensations for investments in its

17   utility infrastructure. As outlined by the FEA witnesses in this proceeding, these

18   objectives can be achieved by pursuing the following:

19   1. A cost-based pricing structure that provides efficient price signals to
20   customers that encourage them to modify energy consumption behavior,
21   make investments in energy assets, and more efficiently consume power
22   from APS. More efficient consumptions by customers can help increase
23   the load factor for APS, and thus spread its fixed cost over more kilowatt-
24   hours. This objective of more efficient consumption by customers will
25   reduce the per unit cost down toward the $0.09/kWh target identified by
26   the Commissioner. As such, using cost-based cost of service principles,
27   adjusting prices to reflect cost of service, and providing strong economic
28   incentives for customers to modify consumption behavior to reduce costs,
29   and increase APS's load factor are critical steps toward meeting the
30   objective identified by the Commissioner.

31   2. Reducing the utility's revenue requirement to reflect only prudent and
32   reasonable cost of providing service, differentiating investments between
33   those funded by investor capital and those funded by customers, or other
34   investment options that do not create costs to customers, and also
35   requiring the Company to manage its system in a way that minimizes

1   operating expenses, and Administrative & General costs are critical to
2   making the utility's rates more competitive.

3   3. Providing the utility fair compensation on its original cost investments, and
4   the fair value of those investments is also critically important. More
5   specifically, the current practice of adding a fair value increment to the rate
6   of return on original cost provides Arizona utilities far more compensation
7   than that awarded to other utilities around the country for ratemaking
8   purposes. This increased cost to customers for APS does not appear to
9   be justified based on its financial standing. Specifically, as noted by my
10   colleague Christopher C. Walters,[17] APS has a bond rating from Standard
11   & Poor's and Moody's of A- and A2, respectively. APS's bond rating is
12   reasonably aligned with the industry normal bond rating as outlined in
13   Mr. Walters' testimony.[18] There, he shows a majority, 53%, of the
14   regulated electric utilities have bond ratings of A- from S&P, while 32%
15   have ratings in the BBB range (BBB- to BBB+).[19]

16   4. While fair value increments are not common in rate-setting practices
17   around the country, the electric utility industry still has very strong
18   valuation metrics based on prospective and historical earnings, cash flows
19   and net book value that outline the original cost of investments made in
20   utility infrastructure. As outlined in Mr. Walters' testimony, these valuation
21   metrics for utility companies are very robust right now, indicating very
22   strong valuations and access to significant amounts of equity and debt
23   capital for utility companies in the current marketplace.

24   5. These strong valuations are produced by setting rates of return on
25   common equity investments in the mid-9.5% area, which have maintained
26   strong credit standing, strong equity valuations, and strong stock price
27   performance.

28   Q   **SHOULD THE COMMISSION CONSIDER SECURITIZATION BONDS FOR**

29   **ABANDONED PLANT COSTS AS A MEANS OF MITIGATING COSTS ON**

30   **CUSTOMERS?**

31   A   The fair value of abandoned plant costs is likely near zero. Hence, if the Commission

32   is considering allowing the utility to recover abandoned plant costs as part of its cost

33   of service, despite the fact that plant is no longer in-service and therefore it has little

34   to no fair value, then the Commission should recognize this in designing its total

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[17]Walters Direct at 18.
[18]*Id.* at 7.
[19]*Id.*

1   revenue requirement, including merits of allowing a fair value operating increment in

2   setting rates. To the extent the Commission decides it is appropriate to allow a utility

3   to recover abandoned plant costs, then the carrying charge on those plant costs

4   should be minimized. If securitization bonds are considered for use in rate-setting,

5   then the Commission should take care to ensure that customers' rates are reduced

6   by the use of securitization bonds. Evaluating the economics of using securitization

7   bonds should include both reduction in the annual carrying charge, and reflection of

8   accumulated deferred income taxes for plant balances that are written off for income

9   tax purposes and no longer used and useful for regulatory purposes. These

10   accumulated deferred income tax balances should be carried over the period of the

11   amortization bonds, and used to reduce costs to customers, in order to ensure that

12   customers get the maximum benefits by the use of securitization bonds.

13   **Q**   **DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?**

14   A   Yes, it does.

Arizona Public Service Company

Total Company
Updated Ocotillo Deferral Adjustment
Declining Balance Recovery - 8.61% WACC
($000)

Line	Description	Asset Balance (1)	ADIT (2)	Rate Base Value (3)	Asset Amort. (4)	Oper. Income And Taxes (5)	Revenue Req. (6)	Taxes Amort. (7)
1	Rate					8.61% [1]		24.75%
2	Year 1	95,073	(23,530)	71,542	9,507	6,160	15,667	(2,353)
3	Year 2	85,565	(21,177)	64,388	9,507	5,544	15,051	(2,353)
4	Year 3	76,058	(18,824)	57,234	9,507	4,928	14,435	(2,353)
5	Year 4	66,551	(16,471)	50,079	9,507	4,312	13,819	(2,353)
6	Year 5	57,044	(14,118)	42,925	9,507	3,696	13,203	(2,353)
7	Year 6	47,536	(11,765)	35,771	9,507	3,080	12,587	(2,353)
8	Year 7	38,029	(9,412)	28,617	9,507	2,464	11,971	(2,353)
9	Year 8	28,522	(7,059)	21,463	9,507	1,848	11,355	(2,353)
10	Year 9	19,015	(4,706)	14,308	9,507	1,232	10,739	(2,353)
11	Year 10	9,507	(2,353)	7,154	9,507	616	10,123	(2,353)
12	Year 11	-	-	-	-	-	-	-
13	**Total**				95,073			(23,530)
14	**Net Present Value**					24,830	86,906	

Sources:
EAB-WP13RB - RB Ocotillo Modernization Project Deferral Update and EAB-WP14RB - IS Amortize Ocotillo Modernization Project Deferral Update.

[1] Pre-tax ROR on original cost rate base, Direct Testimony of Christopher C. Walters.

Arizona Public Service Company

Total Company
Updated Ocotillo Deferral Adjustment
Levelized Recovery - 4.10% Cost of Debt
($000)

Line	Description	Asset Balance (1)	ADIT (2)	Rate Base Value (3)	Asset Amort. (4)	Oper. Income And Taxes (5)	Revenue Req. (6)	Taxes Amort. (7)
1	Rate					4.10% [1]		24.75%
2	Year 1	95,073	(23,530)	71,542	8,261	2,933	11,194	(2,045)
3	Year 2	86,812	(21,486)	65,326	8,516	2,678	11,194	(2,108)
4	Year 3	78,296	(19,378)	58,918	8,778	2,416	11,194	(2,173)
5	Year 4	69,518	(17,206)	52,312	9,049	2,145	11,194	(2,240)
6	Year 5	60,469	(14,966)	45,503	9,328	1,866	11,194	(2,309)
7	Year 6	51,140	(12,657)	38,483	9,616	1,578	11,194	(2,380)
8	Year 7	41,524	(10,277)	31,247	9,913	1,281	11,194	(2,453)
9	Year 8	31,611	(7,824)	23,788	10,219	975	11,194	(2,529)
10	Year 9	21,393	(5,295)	16,098	10,534	660	11,194	(2,607)
11	Year 10	10,859	(2,688)	8,171	10,859	335	11,194	(2,688)
12	Year 11	(0)	0	(0)	0	(0)	-	(0)
13	**Total**				95,073			(23,530)
14	**Net Present Value**					14,381	90,343	

Sources:
EAB-WP13RB - RB Ocotillo Modernization Project Deferral Update and EAB-WP14RB - IS Amortize Ocotillo Modernization Project Deferral Update.
[1] APS Schedule D-1.

BEFORE THE

ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION
OF ARIZONA PUBLIC SERVICE
COMPANY FOR A HEARING TO
DETERMINE THE FAIR VALUE OF THE
UTILITY PROPERTY OF THE COMPANY
FOR RATEMAKING PURPOSES, TO FIX
A JUST AND REASONABLE RATE OF
RETURN THEREON, TO APPROVE RATE
SCHEDULES DESIGNED TO DEVELOP
SUCH RETURN

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DOCKET NO.
E-01345A-19-0236

Surrebuttal Testimony and Attachment of

Christopher C. Walters

On behalf of

Federal Executive Agencies

December 4, 2020

BAI

BRUBAKER & ASSOCIATES, INC.

BEFORE THE

ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	))))))))))))) DOCKET NO. E-01345A-19-0236

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Attachment CCW-1SR

BEFORE THE

ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-01345A-19-0236

Surrebuttal Testimony of Christopher C. Walters

1 **Q   PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A   Christopher C. Walters.   My business address is 16690 Swingley Ridge Road,

3   Suite 140, Chesterfield, MO 63017.

4 **Q   ARE YOU THE SAME CHRISTOPHER C. WALTERS WHO PREVIOUSLY FILED**

5   **TESTIMONY IN THIS PROCEEDING?**

6 A   Yes.   On October 2, 2020, I filed Direct testimony on behalf of the Federal Executive

7   Agencies ("FEA").

8 **Q   WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?**

9 A   The purpose of my surrebuttal testimony is to respond to the rebuttal testimonies of

10   APS witnesses Ms. Bulkley and Mr. Shipman. I will also respond to certain concerns

11   provided in the November 17th letter to the Company and the parties to this proceeding

12   from Commissioner Ms. Lea Márquez Peterson.   My silence with regard to any

1   particular argument raised by the Company through its witnesses should not be

2   construed as tacit agreement.

3   <u>**RESPONSE TO MS. BULKLEY**</u>

4   **Q   DO YOU HAVE ANY INITIAL OBSERVATIONS REGARDING MS. BULKLEY'S**

5   **REBUTTAL TESTIMONY THAT YOU WOULD LIKE TO ADDRESS?**

6   A   Yes. At page 110 of her rebuttal testimony, Ms. Bulkley states the following:

7   In addition, in his Table 12, Mr. Walters misleadingly presents his
8   recommended ROE within a column entitled "Adjusted." However,
9   the 9.3 percent figure recommended by Mr. Walters' represents his
10   own judgment of a final recommended ROE, based on his own
11   analyses. Conceptually, it does not belong in his table of
12   adjustments to my calculations.

13   Notably, though Mr. Walters recommends an ROE of 9.3 percent
14   throughout his testimony, in the course of making "adjustments" to
15   my calculations, he writes that the data supports an ROE of 9.2
16   percent. This seems to be a residual number from some earlier
17   version of Mr. Walters' work on this APS case—hinting at a lack of
18   firmness in his final, subjective recommendation.

19   Given this quoted segment from Ms. Bulkley's testimony, it seems clear that she

20   did not read a data response provided to her addressing the same items she is taking

21   issue with here. Specifically, in response to Data Request No. APS 2.6. Below, I

22   provide the question from APS and FEA's response that address this matter.

23   <u>**Data Request No. APS 2.6:**</u>
24   Referencing page 58, lines 1-3. Please confirm that the 9.20 percent
25   discussed is not based on Ms. Bulkley's testimony or analyses.

26   <u>**Response:**</u>
27   Please note that "9.2%" on line 3 of page 58 will be corrected to
28   "9.3%." Mr. Walters will correct this on the stand at the hearing. The
29   reference to 9.3% is based on the recommended ROE offered by
30   FEA witness Walters and the results of Ms. Bulkley's analyses after
31   certain adjustments were made by Mr. Walters as shown in Col. 2
32   of Table 12 on page 58. After adjustments were made to Ms.

1 Bulkley's models by Mr. Walters, none of the results exceeded his
2 recommended ROE.[1]

3 FEA explained in the data response that the error would be corrected on the

4 stand. This is a simple typographical error. Nothing in FEA's response, or my

5 testimony, suggests this is based on an "earlier version" of my testimony, nor does it

6 hint "at a lack of firmness" in my recommendation. Given the relative position of the

7 numbers "2" and "3" on any keyboard, it is reasonable to conclude that this was a simple

8 typographical error and not a juggling of judgement or "lack of firmness" in making my

9 recommendation as Ms. Bulkley has baselessly asserted. As I have pointed out in my

10 Direct testimony, and will point out multiple times throughout this testimony, there are

11 multiple instances that point to a "lack of firmness" underlying Ms. Bulkley's testimony

12 and analysis. As such, Ms. Bulkley's baseless allegation quoted above is quite

13 hypocritical and should be completely disregarded.

14 Further, I have also explained that the 9.3% referenced in my Table 12 as

15 well as line 3 on the same page are based on my recommendation. FEA explained in

16 the data response that after I made adjustments to Ms. Bulkley's models, the results of

17 those adjusted models do not exceed my recommended ROE. As none of the adjusted

18 results exceeded my recommended ROE of 9.3%, it was, and still is, reasonable to

19 conclude that my recommended ROE of 9.3% is appropriate. In addition, when looking

20 at Table 12 provided on page 58 of my Direct testimony, I have clearly indicated that

21 the 9.3% under column 2 is my recommended ROE, as "Recommended ROE" is the

22 title of the line in which it is referenced. It is to be compared to the adjusted results

23 provided above it under the same column.

---

[1] FEA's response to APS Data Request No. 2.6.

1 **Q PLEASE DESCRIBE HOW MS. BULKLEY RESPONDS TO THE ROE**

2 **RECOMMENDATIONS OF THE OPPOSING ROE WITNESSES.**

3 A At page 16 of her rebuttal testimony, Ms. Bulkley states that the ROE recommendations

4 offered by the opposing witnesses,[2] which are in the range of 8.74% to 9.40% fall "well

5 below the vast majority of authorized ROEs for vertically-integrated electric utilities

6 since January 2018."[3] As support for this statement, she refers to Figure 2 on

7 page 17 of her rebuttal testimony. As described by Ms. Bulkley, her Figure 2

8 represents the individual authorized ROEs for vertically-integrated electric utilities from

9 January 2018 through September 2020. On her Figure 2, she shows where the ROE

10 recommendations of the opposing witnesses lie in relation to the individual authorized

11 ROEs for vertically-integrated electric utilities.

12 **Q PLEASE RESPOND.**

13 A As an initial matter, Ms. Bulkley's Figure 2 fails to show where her recommendation of

14 10.0% lies in relation to authorized ROE decisions since 2018 which she is comparing

15 the recommendations of the Opposing Witnesses to. A quick glance of her Figure 2

16 will show that the overwhelming majority of the decisions provided there fall well below

17 10.0%.

18 Second, Ms. Bulkley's description of her Figure 2 suggests that it is only

19 considering the authorized ROEs of vertically-integrated electric utilities since 2018.

20 However, a review of the workpaper purportedly used to create her Figure 2 will reveal

21 that she has included authorized ROEs for both vertically-integrated and distribution

22 utilities. To put in her own words, this hints at a "lack of firmness" in her analysis.

---

[2]Opposing witnesses are Mr. David Parcell (Staff), Mr. John Cassidy (RUCO), Mr. Kevin Higgins (AECC), and myself (FEA).
[3]Bulkley's rebuttal at 16.

1   In addition, Ms. Bulkley appears to have excluded a recent ROE decision.

2   Specifically, Ms. Bulkley fails to include the 8.20% ROE awarded to Green Mountain

3   Power Corp. in Vermont on August 27, 2020. This exclusion goes unexplained by Ms.

4   Bulkley in her testimony and workpapers. I find this exclusion curious for three reasons:

5   (1) this ROE was awarded well within her observed time period that ended

6   September 30, 2020; (2) she included the August 29, 2019 ROE of 9.06% for the same

7   utility in the same state of Vermont in her graph; and (3) more surprisingly, she appears

8   to have deliberately deleted the 8.2% ROE without explanation for why she excluded

9   this particular recent observation. The underlying data used to create her Figure 2

10   includes the August 27, 2020 decision for Green Mountain Power Corp.; however, the

11   ROE of 8.2% appears to have been deleted. In other words, while Ms. Bulkley's data

12   download from SNL Financial (now S&P Global Market Intelligence) appears to have

13   included the Green Mountain Power Corp. rate case decision, it also appears that she

14   has deliberately deleted the 8.2% ROE without explanation. I say this appears to be

15   deliberate because all of the other details surrounding this particular rate case for

16   Green Mountain Power Corp. in Vermont are provided in her workpaper including the

17   state, utility's name, docket number, and the date the case was filed. This is suspect

18   to say the least.

19   Finally, the scatterplot in the workpaper file provided by Ms. Bulkley in support

20   of her Figure 2 titled "AEB-WP03RB_Figure 2_Authorized ROEs for Integrated

21   Electric.xlsx" does not match the scatterplot titled Figure 2 on page 17 of her rebuttal

22   testimony. The scatterplot provided in her workpaper that is supposed to be in support

23   of her Figure 2 is provided below as my Figure 1.

FIGURE 1
Ms. Bulkley's Figure 2 Presented in her Workpapers
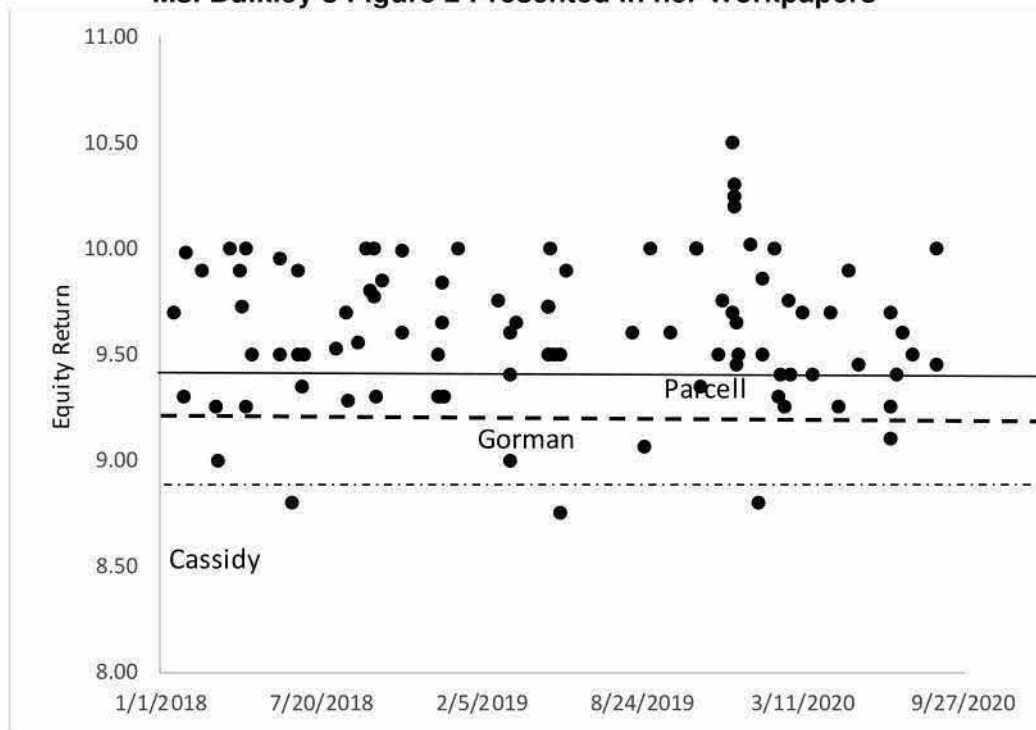

1   As can be seen in the scatterplot from Ms. Bulkley's workpaper in support of

2   her Figure 2, Ms. Bulkley has included horizontal lines that appear to represent the

3   ROE recommendations from witnesses Cassidy, Parcell, and Gorman. There are two

4   things to note about this chart. First, my name does not appear on it. Second, there is

5   a name of a witness (Gorman) that is not presenting ROE testimony in this proceeding,

6   that I am aware of, on the scatterplot provided in her workpaper supporting her

7   Figure 2. To put in her own words, again, this appears to be a "residual" version of this

8   graph provided in another testimony where witnesses Cassidy, Parcell, and Gorman

9   were witnesses and hints at a "lack of firmness" in her analysis.

1　Q　**DID MS. BULKLEY REVIEW VIX FUTURES IN HER REBUTTAL TESTIMONY?**

2　A　Yes. She concluded that investors are expecting increased volatility through at least

3　　　June 3, 2021 as the economy recovers from the economic effect brought on by the

4　　　pandemic.

5　Q　**HAVE INVESTOR EXPECTATIONS REGARDING VOLATILITY CHANGED SINCE**

6　　　**MS. BULKLEY HAS REVIEWED VIX FUTURES?**

7　A　Yes. As shown below in Figure 2, I have provided the futures prices for the available

8　　　expiration months as of November 30, 2020 relative to the VIX futures at the time of

9　　　Ms. Bulkley's updated analysis (i.e., September 30, 2020). As can be seen, there has

10　　been a significant decline in the expected volatility as measured by the VIX. This is

11　　likely the case for two reasons: (1) the U.S. presidential election is over; and (2)

12　　multiple vaccines appear imminent and are currently being distributed in anticipation of

13　　their approval. These two events have likely removed some uncertainty for the near-

14　　to intermediate-term.

FIGURE 2
CBOE VIX Futures as of November 30, 2020.
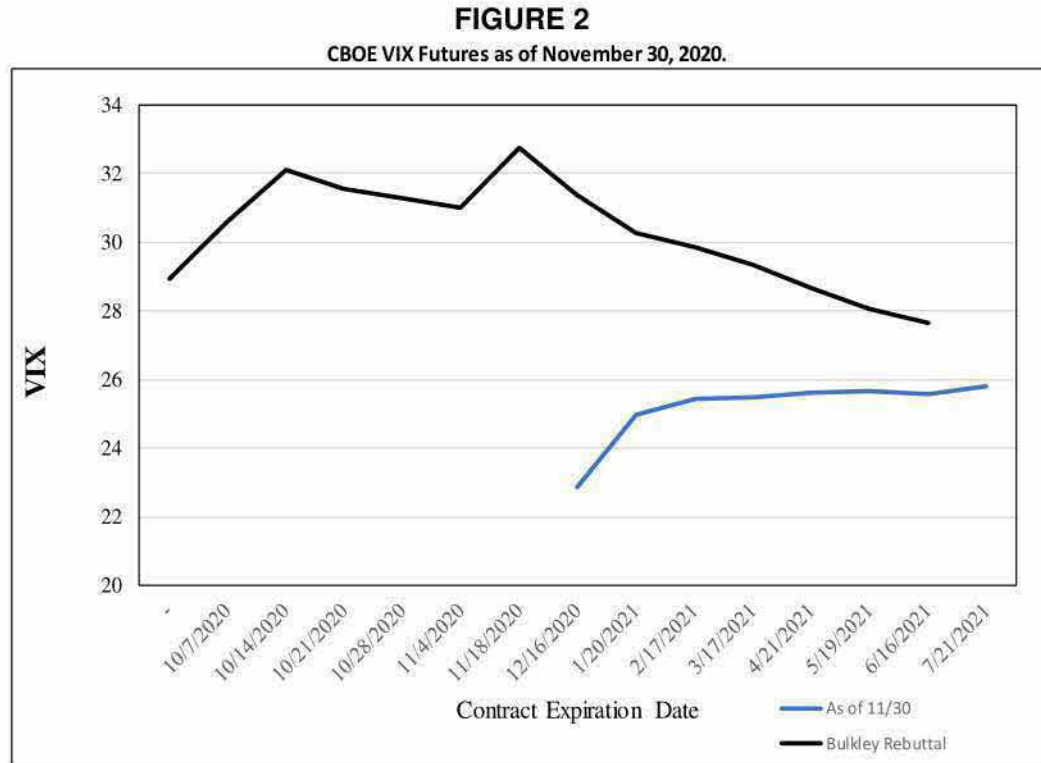
1 **Q MS. BULKLEY STATES THAT THE RESULTS OF YOUR SUSTAINABLE GROWTH**

2 **AND MULTI-STAGE DCF ANALYSES ARE BELOW THE AVERAGE RETURNS**

3 **THAT HAVE BEEN RECENTLY AUTHORIZED FOR VERTICALLY-INTEGRATED**

4 **ELECTRIC UTILITIES. PLEASE RESPOND.**

5 A Ms. Bulkley summarizes my Multi-Stage DCF results as being between 8.64% and

6 8.67% and my Sustainable Growth DCF results as being in the range of 9.17% to

7 9.18% based on the means. She supports her conclusion, in part, by stating that I

8 "must be attributing some value to the output of [my] Multi-Stage DCF model even

9 though it produces results well below the ROE authorized for any vertically-integrated

10 electric utility since January 2018."[4] She refers to Figure 2 of her rebuttal testimony on

---

[4]Bulkley's rebuttal at 81.

1   page 17. Ms. Bulkley's Figure 2 allegedly represents the individual authorized ROEs

2   for vertically-integrated utilities from January 2018 through September 2020.

3   As an initial matter, considering the average authorized ROE for

4   vertically-integrated electric utilities has generally fallen over the last 10 years,

5   arithmetically, commissions have been awarding ROEs below the trailing averages for

6   quite some time now. I show the trend in annual authorized ROEs since 2011 in

7   Figure 3 below.

FIGURE 3

Change in ROE
Vertically Integrated Electric Utilties
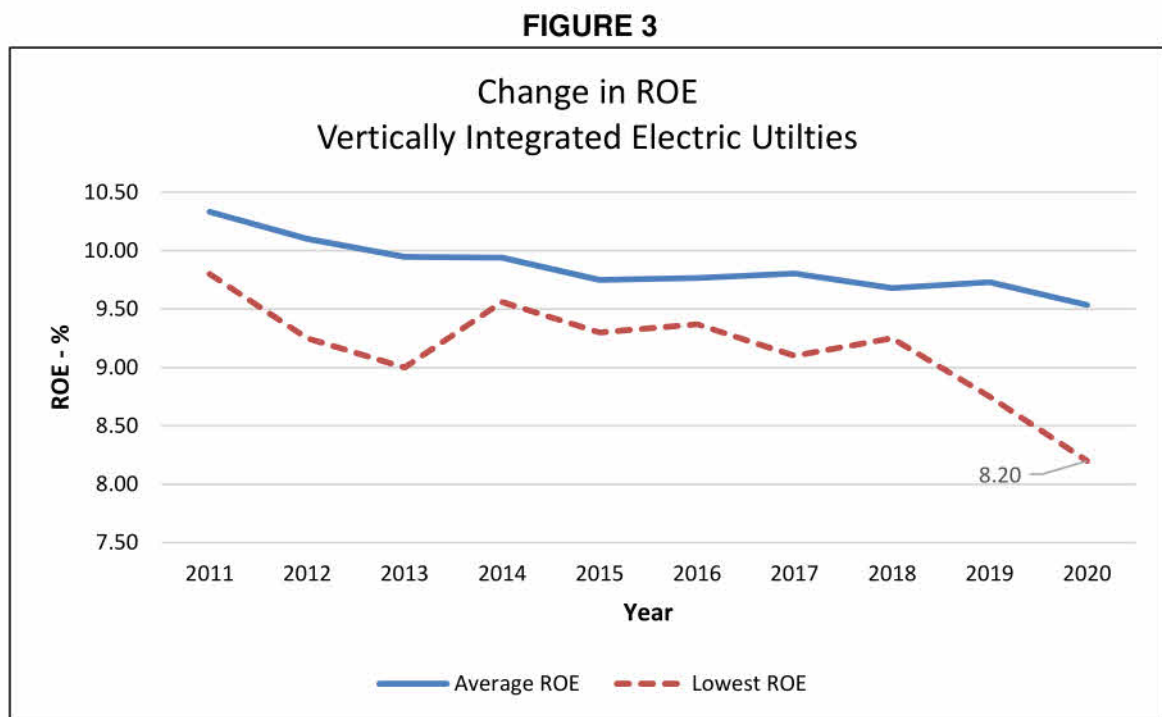
8   Further, Ms. Bulkley's allegation that my Multi-Stage DCF analysis produced

9   results "well below the ROE authorized for any vertically-integrated electric utility since

10   January 2018" and her Figure 2, are factually incorrect. While she correctly describes

11   the mean of my Multi-Stage DCF model producing results between 8.64% and 8.67%,

12   she seemingly ignores the median results of 8.77% and 8.78%, which were provided

13   in Table 7 on page 35 of my Direct testimony where I opined on what I believed a

14   reasonable ROE was based on the results of my DCF analyses. The lowest ROE

1   provided on her Figure 2 is 8.75% which was awarded to Otter Tail in May 2019. The

2   median results of my Multi-Stage DCF model are slightly higher than this result. This

3   alone suggests that Ms. Bulkley's assertion that this model produces results "well below

4   the ROE authorized for any vertically-integrated electric utility since January 2018" is

5   factually incorrect.

6   Finally, as I explained above, and show in Figure 3, 8.75% is not the lowest

7   ROE awarded to a vertically integrated electric utility over this time period. As I

8   explained, Ms. Bulkley seems to have deliberately deleted an authorized ROE of 8.2%

9   that occurred in August 2020. Including this deleted ROE result from the Green

10   Mountain Power Corp. rate case in Vermont makes her assertion completely

11   inaccurate.

12   **Q   PLEASE SUMMARIZE MS. BULKLEY'S CONCERNS WITH YOUR RISK PREMIUM**

13   **ANALYSES.**

14   A   Ms. Bulkley is concerned that I distance myself from the underlying data by relying on

15   annual averaged data in my five-year average risk premiums. She disagrees with my

16   characterization of her regression-derived inverse relationship as simplistic, and

17   suggests that my Risk Premium analysis understates the cost of equity because the

18   average Treasury yield during the five-year period which my risk premium was based

19   is higher than the projected Treasury yield used to estimate the cost of equity.

1   Q   **PLEASE RESPOND TO MS. BULKLEY'S CONCERNS WITH HER ASSERTION**

2   **THAT YOU HAVE DISTANCED YOURSELF FROM THE UNDERLYING DATA BY**

3   **RELYING ON THE MOST RECENT FIVE-YEAR AVERAGE EQUITY RISK**

4   **PREMIUM.**

5   A   In support of this assertion, Ms. Bulkley observes that the risk premium has increased

6   since 2018 as shown on my Attachment CCW-12DR. She asserts that it would then

7   be more appropriate to rely on the risk premium that reflects current market conditions

8   rather than an average that takes into consideration historical market conditions.

9   Importantly, my five-year equity risk premiums do take into consideration the most

10   recent equity risk premium of 7.84% during 2020. My recommended equity risk

11   premium over the 2016-2020 period of 7.02% is 20% weighted by the 2020 year-to-

12   date equity risk premium, which is undeniably an anomalous year. As I explain in my

13   Direct testimony, I incorporated the rolling-averages over five- and ten-year periods to

14   mitigate the impact of anomalous conditions. I have implemented this method for

15   multiple years now. Ms. Bulkley's concerns here are misplaced.

16   Q   **MS. BULKLEY DISAGREES WITH YOUR CHARACTERIZATION OF A**

17   **REGRESSION-BASED INVERSE RELATIONSHIP AS SIMPLISTIC. SHE ALSO**

18   **ASSERTS THAT YOUR RISK PREMIUM ANALYSIS UNDERSTATES THE COST**

19   **OF EQUITY BECAUSE THE AVERAGE TREASURY YIELD DURING THE FIVE-**

20   **YEAR PERIOD WHICH YOUR RISK PREMIUM WAS BASED IS HIGHER THAN THE**

21   **PROJECTED TREASURY YIELD USED TO ESTIMATE THE COST OF EQUITY.**

22   **PLEASE RESPOND.**

23   A   The inverse relationship is calculated using a method known as a "simple" linear

24   regression model. In other words, it relies on changes of a single independent variable

1   to estimate changes in a single dependent variable. The model is not robust enough

2   to capture changes in things that could influence the equity risk premium such as

3   inflation, changes in regulatory regime, changes in political regime or otherwise.

4   In addition, the dynamics of the inverse relationship has changed in recent

5   years. It is easy to see that when observing several recent years of data, there has not

6   been as strong of an inverse relationship. For example, using 2012 as the base year

7   where the average Treasury yield was 2.92% and the equity risk premium was 7.09%,

8   going forward, Ms. Bulkley and her regression model would have us believe that if

9   Treasury yields decreased relative to 2.92%, the equity risk premium would increase

10   relative to 7.09%. However, when looking at the years since 2012, that simply is not

11   true half of the time. In fact, of the eight years since 2012, the directional change in the

12   equity risk premium for four years would be wrongly predicted by her model.

13   Specifically, years 2015-2017, and 2019. Shown in Table 1, I have summarized the

14   realized interest rates and equity risk premiums for each of these years, as well as

15   shown what an inverse relationship would indicate relative to what occurred.

TABLE 1

**Comparison of Actual Directional Changes in the Risk Premium
Relative to what Ms. Bulkley's Inverse Relationship Would Predict**

Year	Treasury Yield	Equity Risk Premium	Interest Rate Relative to 2012	ERP Relative to 2012	Est. Movement in ERP by Bulkley's Model
2012	2.92%	7.09%	-	-	-
2015	2.84%	6.76%	↓	↓	↑
2016	2.60%	7.00%	↓	↓	↑
2017	2.90%	6.79%	↓	↓	↑
2019	2.58%	7.06%	↓	↓	↑

Source: Attachment CCW-12DR

1   The inverse relationship advocated by Ms. Bulkley would have us believe that
2   years where interest rates are lower (higher) than other periods of time, those years
3   should have a higher (lower) equity risk premium. That simply is not the case in recent
4   years.

5   Finally, Ms. Bulkley's testimony and regression analysis spends a lot of time on
6   establishing and supporting an inverse relationship. However, what is overlooked by
7   Ms. Bulkley with regard to this relationship is that it does not imply an increase in the
8   cost of equity. In other words, just because interest rates fall, and her model predicts
9   the equity risk premium to increase, this would not lead to an increased cost of equity.
10   It is quite the opposite, actually. Her model suggests that, as interest rates fall, the
11   equity risk premium is expected to increase. However, the projected increase in the
12   risk premium is not of the same magnitude as the decrease in interest rates, resulting
13   in a reduction in the cost of equity.

1   In any event, her model produces a cost of equity estimate within my

2   recommended range when current and intermediate-projected interest rates are relied

3   upon. The issue then becomes, what is a reasonable interest rate to assume and over

4   what time period?

5 Q   **DO YOU BELIEVE A LONG-TERM PROJECTED INTEREST RATE SUCH AS THE**

6   **PROJECTION THROUGH 2026 USED BY MS. BULKLEY IS RELIABLE?**

7 A   No. I disagree with the use of such a long-term projected interest rate. While investors

8   are likely to rely on projections to some extent in order to make investment decisions,

9   they are also likely to consider the accuracy of previous projections to make their

10   investment decisions. In order to assess the accuracy of the intermediate-term

11   projections from Blue Chip Financial Forecasts, I have expanded the analysis

12   presented in my Attachment CCW-20DR by performing an examination of the projected

13   and actual quarterly interest rates was performed using data from the first quarter of

14   2002 through the first quarter of 2020. This analysis is presented in my

15   Attachment CCW-1SR. I began by performing a regression analysis to determine if

16   there was in fact a relationship between the projected and actual interest rates. If this

17   relationship does exist, what is the strength of the relationship? The regression analysis

18   showed a statistical significance between the projected and actual interest rates with

19   an 82% correlation which is to be expected as each quarterly projection used the

20   previous quarters interest rate as a base. The standard error (SE) of 0.57, however,

21   shows the first signs of weakness when comparing projected and actual interest rates.

22   Standard error (SE) is a measure of the expected difference between our

23   projected and actual interest rates. A SE of 0.57 indicates the actual interest rate has

24   an expected difference of 0.57 percentage points from the projected interest rate. In

1   the examined time period projected interest rates varied between 6.2% and 3.1% while

2   actual interest rates ranged between 5.8% and 1.9%. The variation in actual interest

3   rate magnitudes has a significant impact on the expected calculation error which, as a

4   result, varies between 10% - 30%. A further examination of the difference in projected

5   and actual interest rates, or calculation error, reveals the projected interest rate is, on

6   average, 0.82 percentage points off from the actual interest rate. Again, there is a

7   significant difference in interest rates over the examined period. In order to put this in

8   perspective I examined the percent difference in projected and actual interest rates.

9   This calculation yielded an average error of -25%. That is; the actual interest rate over

10   the examined time period was, on average, 25% lower than the projected interest rate.

11   Based on this analysis, it is clear that economists consistently overestimate

12   actual interest rates over an intermediate time period of six quarters or 18 months.

13   Investors would likely take that into consideration in making their investment decisions.

14   Further, extending the projection period beyond the six quarters in the intermediate

15   projections is likely to be inaccurate on a much greater scale making such a long-term

16   projected rate, such as the one used by Ms. Bulkley that extends out to 2026,

17   completely unreliable. In addition, given current interest rate policy implemented by

18   the Federal Reserve is expected to last at least through 2023, it is unlikely we will see

19   interest rates rise significantly higher than the where they are now, or even beyond

20   what is projected over the intermediate term. As such, the use of a risk-free rate beyond

21   the intermediate term of six quarters out should be rejected in estimating the cost of

22   equity.

1 Q **MS. BULKLEY TAKES ISSUE WITH YOUR ASSERTION THAT INTEREST RATES**

2   **ARE LESS VOLATILE NOW THAN THEY WERE IN THE 1980'S. DO YOU AGREE**

3   **WITH HER RESPONSE?**

4 A No. I disagree with her for multiple reasons. First, I referred to the 1980's as an era of

5   interest rate volatility in general, so the volatility of interest rates should be viewed over

6   the 1980's era as a whole relative to now. Second, when comparing the volatility of

7   interest rates of the 1980's to volatility currently present in interest rates in 2020, we

8   need to look at the volatility present since the enactment of current interest rate policy
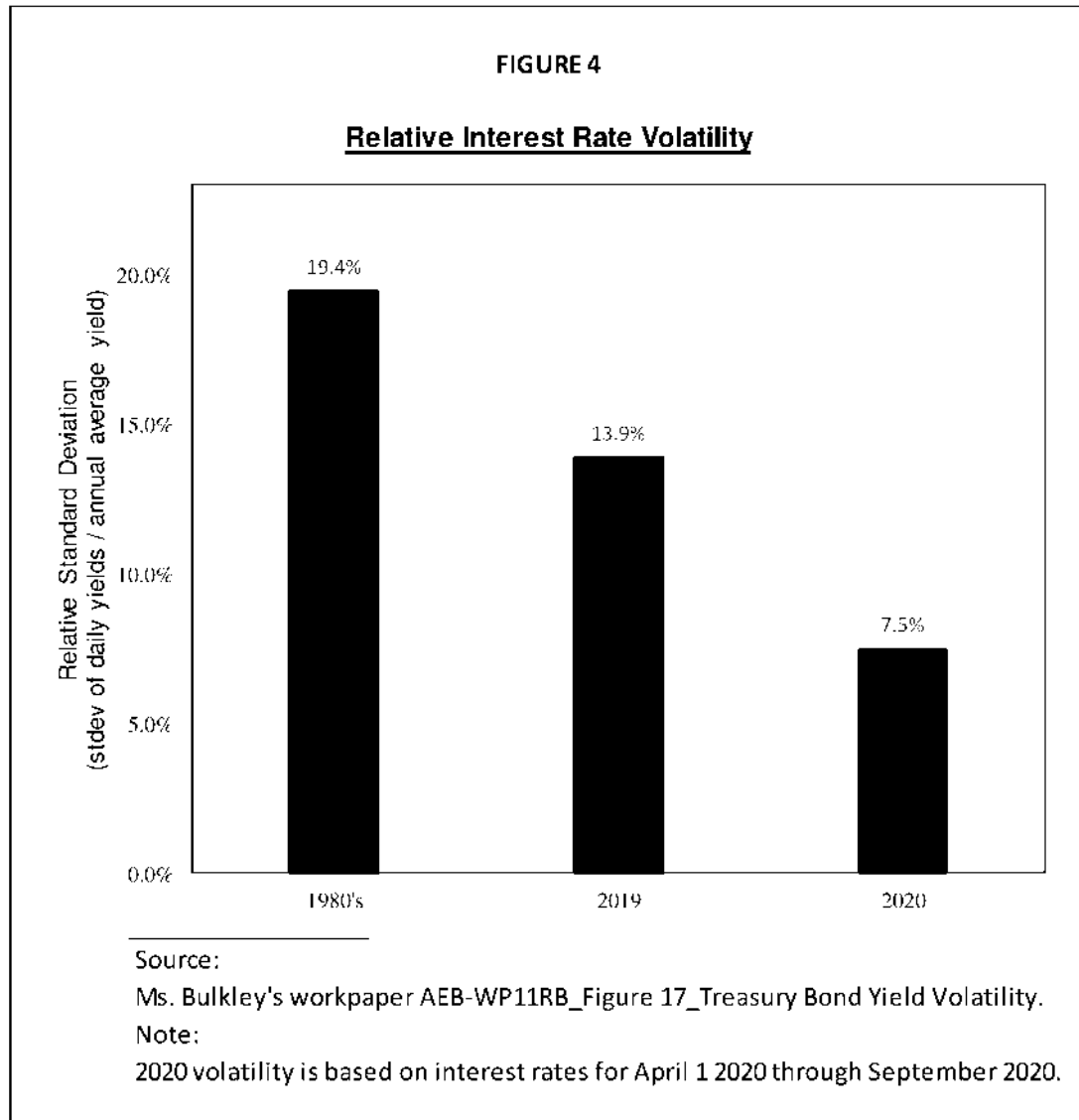
9   (i.e., after March 2020).

10 Q **WHY DO YOU BELIEVE THAT THE VOLATILITY IN INTEREST RATES FOR 2020**

11   **SHOULD BE VIEWED AT AFTER MARCH 2020?**

12 A In March 2020, the Federal Reserve took two actions on interest rates, ultimately

13   cutting the Federal Funds Rate target to be within the range of 0.00% to 0.25%. As I

14   describe later in this testimony, current interest rate policy is expected to be in place

15   through at least 2023, if not later. As such, current interest rate policy is likely to be in

16   effect throughout the duration which rates from this proceeding will be in effect.

17   Therefore, comparing interest rate volatility during the current interest rate policy being

18   employed by the Federal Reserve is appropriate.

19 Q **HOW DOES THE RELATIVE VOLATILITY DURING THE CURRENT INTEREST**

20   **RATE POLICY COMPARE TO THE 1980'S?**

21 A As shown below in Figure 4, the relative volatility in the 1980's is 19.4% compared to

22   7.5% during 2020 since the Federal Reserve's current interest policy was put into place.

23   In other words, the relative volatility in the 1980's is 2.6 times greater than that

1   experienced in 2020 during the current interest rate policy. As such, my assertion that

2   interest rates in the 1980's were more volatile relative to current interest rates is

3   accurate.

FIGURE 4

Relative Interest Rate Volatility

Source:
Ms. Bulkley's workpaper AEB-WP11RB_Figure 17_Treasury Bond Yield Volatility.
Note:
2020 volatility is based on interest rates for April 1 2020 through September 2020.

4 **Q**   **PLEASE SUMMARIZE MS. BULKLEY'S CONCERNS WITH YOUR BETA**

5   **ESTIMATES USED IN YOUR CAPM ANALYSES.**

6 **A**   Ms. Bulkley summarizes my Beta estimates at page 99 of her rebuttal testimony. There

7   she states that I used: (1) Value Line's adjusted Betas as of September 11, 2020;

1 (2) the average of Value Line's adjusted Betas published quarterly from Q3 2014

2 through Q2 2020; and (3) S&P Global Market Intelligence's raw Betas as of

3 September 18, 2020. She refers to these Beta estimates as Beta estimates #1, #2 and

4 #3, respectively. She cites page 44 of my Direct testimony as the reference for the

5 description of the Beta coefficients I relied on for my CAPM.[5]

6   She argues that my Beta estimate #2 is not defensible because previously

7 published Beta estimates are not relevant to the CAPM's aim of calculating investors'

8 prospective required return on equity.[6]

9   Ms. Bulkley then argues that my Beta estimate #3 is not defensible for two

10 reasons: (1) I erroneously refer to the S&P published Betas as "adjusted" when they

11 are in fact raw Betas; and (2) the Betas published by S&P are calculated using a *daily*

12 return interval, while Betas published by Value Line (and Bloomberg) are calculated

13 using weekly return intervals.

14   As an attempt to correct the "raw" Beta estimates, Ms. Bulkley states that

15 "[a]djusting them as per the adjusted Betas published by Value Line changes the S&P

16 Beta from 0.691 to 0.793 (i.e., 0.691*0.67 + 1*0.33)."[7] With regard to the interval period

17 used to estimate Beta (i.e., weekly or daily), Ms. Bulkley asserts that I have understated

18 the Beta from S&P because of the return interval used to estimate Beta, which she

19 states is daily. She states that "selection of a shorter return interval (e.g., daily rather

20 than weekly) biases Beta estimates downward for many companies (such as those in

21 APS's proxy group), making them appear less risky than they really are."[8] She

[5]Bulkley's rebuttal at 99.
[6]*Id.*
[7]*Id.* at 100.
[8]*Id.* at 100.

1   concludes that daily Betas are poor measures of risk and not comparable to weekly

2   Betas.[9]

3 **Q** **PLEASE RESPOND TO MS. BULKLEY'S CONCERNS WITH BETA ESTIMATE #2.**

4 **A** As an initial matter, Beta estimates themselves are historical in nature as raw Beta

5   estimates are based entirely off historical stock prices over varying periods of time

6   depending on the source of the estimate. The only item that makes Beta estimates

7   *arguably* forward-looking are the various adjustments such as those employed by

8   Value Line or Bloomberg. However, there is nothing specific about the adjustment that

9   makes recent Betas more likely to be forward-looking than previously published Betas.

10   Specifically, Value Line and Bloomberg use the Blume adjustment, albeit the

11   adjustment is somewhat different between the two. As S&P notes, "The Bloomberg

12   adjustment is not appropriate for a vast number of situations, as it assigns constant

13   weighting regardless of the standard error in the raw Beta estimation (Bloomberg

14   Beta = 1/3*market Beta + 2/3*raw Beta)."[10] Further, there is nothing about applying the

15   1/3 and 2/3 weighting to Beta that makes it relevant to the near-term. Rather, it is just

16   a constant weighting that is based on stock's tendency to revert towards the market

17   Beta of 1.0. Whether that is within the next week, over the next 150 years, or if ever,

18   is anyone's guess.

19   Further, for several months prior to the onset of COVID-19 and its impact on

20   markets, I included the historical Value Line Beta estimate because I believed Beta

21   estimates were *too low*. As much as Ms. Bulkley would lead us to believe I did this as

22   an attempt to lower my ROE estimates, it just isn't so. I have applied this analysis when

---

[9] *Id.* at 101.
[10] S&P Global Market Intelligence, Beta Generator Model. Bloomberg and Value Line employ slightly different methods of the Blume adjustment, which I will explain later.

1   I believed the recently published Value Line Betas were both too low and too high. It

2   is an attempt to account for what are potential or likely market abnormalities. A quick

3   review of the historical Value Line Betas will show that recent Betas are anything but

4   normal.

5   Finally, it is important to note that I included them as an additional estimate to

6   the currently published Betas from Value Line as well as current Betas from S&P Global

7   Market Intelligence ("MI"). I did not specifically exclude the results of any one model or

8   any one Beta. Her concerns here are misplaced and should be rejected.

9   **Q**   **PLEASE RESPOND TO MS. BULKLEY'S CONCERNS WITH BETA ESTIMATE #3.**

10   A   While I appreciate Ms. Bulkley's testimony on the matter, the fact is, I did not rely on

11   MI's published raw three-year Beta estimates which Ms. Bulkley cites.

12   I relied on MI's "Beta Generator" model to produce Betas that cover a historical

13   period of time identical in length to *Value Line* (i.e., five years), over return intervals that

14   are identical to Value Line (i.e., weekly). However, there are two distinct differences

15   between the MI Beta I relied on and the Value Line Beta: (1) the benchmark index

16   used as the proxy for the market in the MI Beta estimates is the S&P 500 whereas

17   Value Line relies on the New York Stock Exchange ("NYSE"); and (2) the MI Betas I

18   used are adjusted using the Vasicek method whereas the Value Line Betas are

19   adjusted using a modified form of the Blume adjustment. As such, nothing in Ms.

20   Bulkley's rebuttal testimony on the MI Betas, or Beta Estimate #3 as she refers to in

21   her testimony, is applicable to my analysis. As such, I urge the Commission to reject

22   her arguments on the matter in their entirety for being completely untrue.

23   While I appreciate Ms. Bulkley's testimony and research on the "frequency

24   dependence of Beta" on pages 100-101 of her rebuttal testimony, it simply does not

1   apply to my analysis as my Beta estimates from MI are not based on daily return

2   intervals. Rather, they are based on weekly return intervals, which is consistent with

3   Value Line's return intervals that she explicitly agrees with.[11]

4 **Q**   **DO YOU HAVE ANY OTHER COMMENTS REGARDING MS. BULKLEY'S**

5   **ATTEMPT TO CORRECT YOUR MI BETAS?**

6 **A**   Yes. Aside from the fact the Ms. Bulkley's erroneous assertion that my MI Betas are

7   raw, or unadjusted, she has incorrectly incorporated the actual adjustment used by

8   *Value Line.* As an attempt to correct the "raw" Beta estimates, Ms. Bulkley states that

9   "[a]djusting them as per the adjusted Betas published by Value Line changes the S&P

10   Beta from 0.691 to 0.793 (i.e., 0.691***0.67** + 1***0.33**)."[12]

11   As an initial matter, her adjustment to an already-adjusted Beta is unwarranted,

12   not supported by evidence, or any financial text which I am aware. Further, in her

13   attempted correction of my Beta estimates, she states that she incorporated the

14   adjustment methodology used by Value Line. However, she used the traditional Blume

15   adjustment that is traditionally used by Bloomberg. Value Line incorporates a slight

16   change in the weights applied compared to Bloomberg. Specifically, rather than

17   applying a methodology incorporating a 33%*market Beta + 67%*raw Beta weighting

18   like Bloomberg, Value Line calculates its adjusted Beta by incorporating the following:

19   35%*market Beta + 67%*raw Beta.[13] Because this method uses 35% weighting on the

20   market Beta, it over-weights the market Beta of 1.0, ultimately moving the adjusted

21   Beta closer to 1.0 than what the traditional Blume adjustment would estimate for the

22   individual stock. Therefore, in addition to Ms. Bulkley incorrectly describing my Betas

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[11]Bulkley's rebuttal at 100-101.
[12]Bulkley's rebuttal at 100.
[13]This data is not published on Value Line's website. I have independently verified this via email with Value Line representatives.

1   from MI as raw and attempting to correct them by using Value Line's adjustment

2   methodology, she has also incorrectly applied the methodology she said she used to

3   adjust my Betas. As such, Ms. Bulkley's testimony on this matter should be rejected.

4   **Q**   **PLEASE DESCRIBE MI'S METHODOLOGY USING ITS BETA GENERATOR**

5   **MODEL?**

6   **A**   The adjustment method employed by MI is known as the Vasicek method. As MI
7   explains:

8   The Vasicek Method is a superior alternative to the Bloomberg Beta
9   adjustment. The Bloomberg adjustment is not appropriate for a vast
10   number of situations, as it assigns constant weighting regardless of the
11   standard error in the raw beta estimation (Bloomberg Beta = 1/3*market
12   beta + 2/3*raw Beta). Given the statistical fact that a larger sample size
13   yields a smaller error, the Vasicek method more appropriately adjusts
14   the raw beta via weights determined by the variance of the individual
15   security versus the variance of a larger sample of comparable
16   companies. The weights are designed to bring the raw beta closer to
17   whichever beta estimation has the smallest error. This is a feature the
18   Bloomberg beta cannot replicate.

19   Vasicek Adjusted Beta = $(V_i/(V_i+V_m))*B_m + (V_m/(V_i+V_m))*B_i$

20   Where V_i and B_i are the variance and beta of the individual security and
21   V_m and B_m are the average variance and beta of the industry sample.[14]

22   The other significant difference between the MI Beta and Value Line Beta for

23   my proxy group is attributable to the index in which the Betas are calculated against

24   and the adjustment method employed. As explained above, the MI Betas are

25   calculated using the S&P 500 index and are adjusted using the Vasicek method. Value

26   Line Betas are calculated using the New York Stock Exchange and adjusted using a

27   modified version of the Blume method, which is similar to the adjustment used by

28   Bloomberg, which incorporates a constant weighting regardless of the standard error.

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[14]S&P Global Market Intelligence, Beta Generator Model, downloaded on September 23, 2020. S&P Global Market Intelligence specifically references the Bloomberg adjustment. The adjustment employed by Bloomberg is similar to the adjustment employed by Value Line.

1   Q   **DO YOU HAVE ANY ADDITIONAL COMMENTS ON THE DIFFERENCES**

2   **BETWEEN YOUR PROXY GROUP'S BETA FROM VALUE LINE AND MI?**

3   A   Yes. As noted above, Value Line Betas are estimated using the entire NYSE as the

4   benchmark, whereas the MI Betas are estimated using the S&P 500. Because no

5   analyst presenting a CAPM analysis in this proceeding relies on the NYSE as a proxy

6   for the market, which the MRP is calculated from, this alone makes the Value Line

7   Betas less preferable. Betas employed in a CAPM should be calculated using the

8   benchmark index that is also used as a proxy for the overall market. Ms. Bulkley and I

9   both relied on the S&P 500 as the proxy for the overall market in estimating our MRP.

10   While Value Line Betas are commonly used in CAPM analyses presented in regulatory

11   proceedings such as this one, it is theoretically incorrect to do so unless the NYSE is

12   used as the proxy for the overall market used to calculate the MRP.

13   Q   **PLEASE SUMMARIZE MS. BULKLEY'S CONCERNS WITH YOUR MRP**

14   **ESTIMATES USED IN YOUR CAPM ANALYSES.**

15   A   As an initial matter, Ms. Bulkley complains about my use of the projected risk-free rate

16   to calculate each of my MRP estimates. In addition to my use of the projected risk-free

17   rate, Ms. Bulkley offers several criticisms for each of my three MRP estimates.

18   Ms. Bulkley's criticisms of my MRP #1 (9.4%) are that it is not "forward-looking,"

19   the historical market return component includes negative returns from 2008, and that

20   my use of a historical real return on the market with a projected rate of inflation ignores

21   an inverse relationship between interest rates and the equity risk premium.[15]

22   Ms. Bulkley's criticisms of my MRP #2 (11.6%) are that it is only reflective of a

23   single source for growth rate estimates compared to her use of both Bloomberg and

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[15]Bulkley's rebuttal at 102-103.

1   the S&P Earnings and Estimates Report, and that I used a 'less-conservative' method

2   in applying the constant growth DCF model using a full-year of growth relative to her

3   using a half-year of growth when adjusting the dividend yield.[16]

4   Ms. Bulkley's criticism of my MRP #3 (10.1%) is that I used a version of the

5   FERC's two-step DCF methodology even though FERC relies on a single-step DCF to

6   estimate the market return.

7 **Q PLEASE RESPOND TO MS. BULKLEY'S CRITICISMS OF YOUR RISK-FREE RATE**

8   **USED TO CALCULATE THE MRP AND USED IN YOUR CAPM.**

9 A   Ms. Bulkley seems be concerned with my choosing to not rely on the current yield on

10   Treasury bonds as well as a long-term projected Treasury yield. As an initial matter, I

11   do not recall having ever relied on the current yield on Treasury bonds in estimating

12   the MRP or within my CAPM. As long as I can remember, I have relied on the projected

13   30-year Treasury yield for six quarters out as published in Blue Chips Financial

14   Forecast. Her testimony has not convinced me to deviate from that approach.

15   Finally, Ms. Bulkley opines that a long-term projected risk-free rate may more

16   closely match the period when APS's rates from this proceeding will be in effect. As of

17   June 1, 2020 that long-term projected rate is 3.0% for the period covering 2022-2026.

18   Given the Federal Reserve's expectation to leave interest rates near zero through

19   2023, if not longer,[17] it is improbable that long-term Treasury yields can increase from

20   1.42% as reported in Ms. Bulkley's updated analysis to the projected yield 3.00% which

21   was projected in June 2020. In its September 16, 2020 Statement, the Federal Reserve

22   stated as follows:

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[16]*Id.* at 103-104.

[17]FederalReserve.gov, Press Release: Federal Reserve issues FOMC statement, September 16, 2020. https://www.federalreserve.gov/newsevents/pressreleases/monetary20200916a.htm

1 The Committee decided to keep the target range for the federal
2 funds rate at 0 to 1/4 percent and expects it will be appropriate to
3 maintain this target range until labor market conditions have reached
4 levels consistent with the Committee's assessments of maximum
5 employment <u>and inflation has risen to 2 percent and is on track to</u>
6 <u>moderately exceed 2 percent for some time.</u>[18]

7 As shown on the Federal Reserve's Economic Projections released on the

8 same day as the quoted statement above, it does not expect inflation to reach its target

9 2.0% until at least 2023.[19] The Federal Reserve's statement states that it will keep the

10 target rate between 0 and 0.25% until inflation is expected to exceed 2.0% for some

11 time after it gets there. In other words, even if inflation does reach the target of 2.0%,

12 the Federal Reserve might not increase interest rates if it does not reasonably expect

13 inflation to maintain a 2.0% level. Even when the Federal Reserve does start to

14 normalize interest rates, it does not necessarily translate into higher 30-year Treasury

15 rates. I show a clear example of this in Figure 3 on page 16 of my Direct testimony. In

16 fact, even as the FOMC initially started to increase the Federal Funds Rate, 30-year

17 Treasury yields decreased over the intermediate term. As such, it is more likely that

18 the 30-year Treasury yield during the period in which the rates are in effect for APS as

19 a result of this proceeding are closer to the current or near-term projected yields.

20 **Q PLEASE RESPOND TO MS. BULKLEY'S CRITICISMS OF MRP #1.**

21 A Ms. Bulkley's concerns with my MRP #1 that is based on the historical real return on

22 the market plus projected inflation are also misplaced. With regard to relying on

23 historical estimates of the market risk premium, Dr. Morin states in his book, *New*

24 *Regulatory Finance:*

25 Although realized returns for a particular time period can deviate
26 substantially from what was expected, it is reasonable to believe that
27 long-run average realized returns provide an unbiased estimate of what

---

[18]*Id.*
[19]https://www.federalreserve.gov/monetarypolicy/files/fomcprojtabl20200916.pdf

1   were expected returns. This is the fundamental rationale behind the
2   historical risk premium approach. <u>Analysts and regulators often assume</u>
3   <u>that the average historical risk premium over long periods is the best</u>
4   <u>proxy for the future risk premium.</u>[20]

5   Dr. Morin concludes that "[t]here are two broad approaches to estimating the risk

6   premium: retrospective and prospective. Each has its own strengths and weaknesses,

7   hence the need to utilize both methods."[21] For these reasons, I conclude that my

8   reliance on multiple estimates of the market risk premium is balanced and reasonable.

9   If anything, by not considering some sort of historical data in her analysis, it is likely

10   that Ms. Bulkley's estimates are biased.

11   With regard to Ms. Bulkley's reference to the Duff & Phelps text in support of

12   her concern over the historical period including negative returns in 2008, it is irrelevant.

13   While market returns and the risk premium are likely to fluctuate year-over-year and

14   from what was expected, it is reasonable to believe that long-run average realized

15   returns provide an unbiased estimate of what were expected returns, as noted by Dr.

16   Morin.[22] Further, while the historical period does include the negative returns for 2008,

17   it also includes recent irrational market returns in excess of 30% for 2019 and 2013.

18   Further, Ms. Bulkley seemingly ignores the "normalized" estimate of the

19   forward-looking market risk premium of 6.0% advocated by Duff & Phelps which was

20   provided on page 50 of my Direct testimony. In other words, even after taking into

21   consideration the negative returns of 2008, Duff & Phelps, which is also the source Ms.

22   Bulkley relies on to dispute my analysis, recommends a "normalized" MRP of 6.0%.

23   Notably, Duff & Phelps' normalized MRP is relative to 20-year Treasury yields, which

24   tend to be lower than the 30-year yields relied on by both of us.

---

[20]Morin, Dr. Roger A, "New Regulatory Finance," at 156. (Emphasis added.)
[21]*Id.* At 162.
[22]*Id.* at 156.

1   In addition, the normalized risk premium from Duff & Phelps comes from the

2   same page as the "normalized" risk-free rate she used in "Scenario 3" of her Fair Value

3   Increment ("FVI") analysis.

4   **Q   PLEASE RESPOND TO MS. BULKLEY'S CRITICISMS OF MRP #2.**

5   A   Ms. Bulkley's concerns with my MRP #2 are not really criticisms as much as they are

6   a personal preference. She does not state I calculated the expected dividend yield

7   incorrectly or that my source is not reputable. As such, I will not respond to her

8   concerns any further.

9   **Q   PLEASE RESPOND TO MS. BULKLEY'S CRITICISM OF MRP #3.**

10 A   Ms. Bulkley's concern with my MRP #3 is that I implemented a version of FERC's

11   two-step DCF method to estimate the return on the market when the FERC uses a

12   single-step DCF to estimate the return on the market. As I have explained in detail in

13   my Direct testimony, it is not reasonable, let alone plausible, to expect a company within

14   the index to grow at a rate faster than the economy in perpetuity, a key assumption

15   with the constant growth model. This becomes even more important during anomalous

16   market conditions and when certain individual company growth rates are more than

17   15x that of projected GDP growth.[23]

18   Measuring the expected return on the market as Ms. Bulkley has done produces

19   a biased, or skewed upward, result that is based on short-term growth rate estimates

20   for the individual companies that make up the broad market index. Returns of this

21   nature are aberrant and cannot be expected to be sustained over any reasonable

---

[23] I explained at pages 62-65 of my direct testimony, Ms. Bulkley's expected market return included a growth rate of 64.5% for Autodesk, which is approximately 15x more than the projected growth rate of the economy.

1   period of time. Because of underlying individual results such as this, applying multiple

2   methods to calculate the expected market return as I have in this case results in a more

3   reasonable and balanced approach.

4   Finally, while I agree Ms. Bulkley is correct that FERC does not rely on the

5   two-step method to estimate the return on the market, my reason for doing so is

6   grounded in sound financial theory, that no company can grow faster than the economy

7   over the long-term, which I have explained in detail throughout my Direct testimony.

8   She ignores academic and practitioner texts by assuming such growth rates for

9   individual companies that are the basis for her projected market return. Specifically,

10   the CFA Institute notes as follows with regard to earnings growth rates of the composite

11   indices (i.e., S&P 500, NYSE, etc.):

12   Earnings growth for the overall national economy can differ from the
13   growth of earnings per share in a country's equity market
14   composites. This is due to the presence of new businesses that are
15   not yet included in the equity indices and are typically growing at a
16   faster rate than the mature companies that make up the composites.
17   **Thus, the earnings growth rate of companies making up the**
18   **composites should be lower than the earnings growth rate for**
19   **the overall economy.**[24] (Emphasis added.)

20   Ms. Bulkley's concerns here are misplaced.

21 Q   **DID MS. BULKLEY UPDATE HER FAIR VALUE INCREMENT ("FVI") ESTIMATE IN**

22   **HER REBUTTAL TESTIMONY?**

23 A   Yes. Ms. Bulkley updated her FVI analysis to reflect more recent data and to correct

24   the several mathematical errors in her analysis that I identified in my Direct testimony.

---

[24]CFA Program Curriculum, 2014 Level II Vol.1, "Ethical and Professional Standards, Quantitative Methods, and Economics", Paul Kutasovic, Reading 15 – Economic Growth and the Investment Decision, p. 609, footnote 5.

1   Ms. Bulkley summarizes the corrected results of her initial analyses as well as her

2   updated analyses as follows:

3   Based on market data as of August 2019, my recommended FVI
4   cost rate was 0.81 percent (equal to 50 percent of the average real
5   risk-free rate estimate of 1.62 percent). Upon updating with current
6   data, my recommendation is a FVI cost rate of 1.28 percent, equal
7   to my estimate of the real risk-free rate, as shown below in Figure 19
8   and in att AEB-8RB.[25]

9   **Q   DO YOU HAVE ANY COMMENTS ON MS. BULKLEY'S UPDATED FVI ANALYSIS?**

10   A   Yes. As Ms. Bulkley explains, her updated analysis would produce a recommended

11   FVI cost rate of 1.28%. Ms. Bulkley's updated FVI cost rate appears to abandon the

12   Commission's methodology of using half of the calculated risk-free rate which she

13   employed in her Direct testimony. As she explains on page 118 of her rebuttal

14   testimony, lines 14-16, "Based on market data as of August 2019, my recommended

15   FVI cost rate was 0.81 percent (equal to 50 percent of the average real risk-free rate

16   estimate of 1.62 percent)." If she were to apply that same methodology, consistent

17   with her Direct testimony, her recommended FVI cost rate would be 0.64% instead of

18   her updated recommendation of 1.28%. This would also represent a reduction to the

19   Company's request of 0.80% identified by Ms. Bulkley. Notably, if Ms. Bulkley were to

20   be consistent in her methodology she employs between her testimonies, she would

21   produce a FVI cost rate within one basis point of my recommended FVI cost rate of

22   0.65%.

23   If Ms. Bulkley's FVI calculation is to be relied upon in any fashion, it should be

24   done so by implementing the Commission's methodology she initially used, which is by

25   taking half of the calculated real risk-free rate.

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[25]Bulkley's rebuttal at 118.

1   <u>**RESPONSE TO MR. SHIPMAN**</u>

2 **Q**   **PLEASE OUTLINE MR. SHIPMAN'S CRITICISM TO YOUR FINANCIAL INTEGRITY**

3   **ANALYSIS?**

4 A   Mr. Shipman has three issues with my analysis which are summarized below:

5   1. He states that the adjusted debt ratio is no longer used as a core credit metric in
6   S&P's adjusted methodology;

7   2. He states that I calculated the relevant core credit metric of FFO-to Debt incorrectly;
8   and

9   3. He states that my analysis fails to address the Company's business risk, which is a
10   major component of a credit rating.

11 **Q**   **DO YOU AGREE WITH MR. SHIPMAN THAT THE ADJUSTED DEBT RATIO IS NOT**

12   **A CORE CREDIT RATIO FOR CORPORATE ISSUERS?**

13 A   I agree with Mr. Shipman that after S&P changed its methodology in November 2013

14   and later on April 1, 2019, the adjusted debt ratio is no longer used as a core credit

15   metric. In fact on page 53 of my Direct testimony, I pointed out that the two core ratios

16   are FFO-to-debt and debt-to-EBITDA. The purpose of my adjusted debt ratio

17   calculation is two-fold: (1) it is a required component to the adjusted FFO-to-Debt and

18   Debt-to-EBITDA ratios, which are core metrics as shown on page 1 of Attachment

19   CCW-18DR; and (2) to compare it to the industry medians for regulated utility

20   companies with the same credit ratings, which I have done on page 3 of Attachment

21   CCW-18DR.

22   I find this information meaningful and relevant when assessing APS's financial

23   risk. As discussed in my testimony, the Company's adjusted debt ratio based on its

24   regulatory capital structure and S&P's off-balance sheet debt allocated to APS's

25   jurisdiction is 48.5%, which is significantly lower than the industry median adjusted debt

1   ratio of 52.4% for utilities with an A- bond rating. Again, even though this is not a core

2   ratio based on S&P guidelines, I find it useful to evaluate the Company's financial risk.

3   **Q**   **DO YOU AGREE WITH MR. SHIPMAN THAT YOU DID NOT CALCULATE THE**

4   **FFO-TO DEBT RATIO CORRECTLY?**

5   **A**   No, I do not. Mr. Shipman did not identify the mistake that I have presumably made in

6   my calculations of the FFO-to-Debt ratio. His only argument is that my calculated

7   FFO-to-Debt ratio is 27%, which is significantly higher than the S&P estimated ratio of

8   22.5%. However, he failed to recognize the fact that S&P calculates the FFO-to-Debt

9   ratio based on consolidated financial performance of the total company. My analysis

10   differs from S&P's approach. As explained on page 54 of my Direct testimony, I am

11   attempting to judge the reasonableness of my proposed cost of capital for rate-setting

12   in APS's retail regulated utility operations, not on a total company basis. To do so, I

13   applied an allocation factor of approximately 80% to reflect the jurisdictional financial

14   credit metrics.

15   **Q**   **MR. SHIPMAN ALSO ADDRESSES HIS CONCERN THAT YOU DID NOT REFLECT**

16   **THE COMPANY'S BUSINESS RISK. DO YOU AGREE?**

17   **A**   While I agree that S&P and the other major credit rating agencies evaluate the

18   companies' business risk along with their financial risk to establish a corporate credit

19   rating, the purpose of my analysis is not to define APS's credit rating, but to determine

20   whether my proposed rate of return will support cash flow metrics, balance sheet

21   strength, and earnings that will support an investment grade bond rating and APS's

22   financial integrity. Further, the Company's Business Risk ranking from S&P at the time

23   of my Direct testimony was "Excellent." The Company's Business Risk ranking from

1   S&P is unchanged, and is still considered "Excellent." As shown on page 1 of my

2   Attachment CCW-18DR, I provided the ratings matrix that is a combination of business

3   risk and financial risk. The implied rating produced by the combination of the

4   Company's business risk and the financial risk rating that corresponds with my

5   calculations supports the Company's current rating of A- from S&P. Therefore, Mr.

6   Shipman's argument that my failure to identify APS's business risk does not apply.

7   **RESPONSE TO COMMISSIONER PETERSON'S LETTER**

8   Q   **HAVE YOU REVIEWED THE NOVEMBER 17, 2020 LETTER SUBMITTED BY**

9   **COMMISSIONER PETERSON?**

10   A   Yes, I have. In her November 17th letter, Commissioner Peterson has asked the parties

11   to work together in order to achieve a rate decrease in this rate case. She expresses

12   a desire to see average retail rates become more competitive with other states. In her

13   Letter to the parties, Commissioner Peterson has asked the parties to explore several

14   issues as potential avenues to achieve her stated goal.

15

16   Q   **WILL YOU BE ADDRESSING ANY OF THE ISSUES RAISED BY COMMISSIONER**

17   **PETERSON IN HER LETTER?**

18   A   Yes. Specifically, I will be addressing the following issue raised in Commissioner

19   Peterson's letter:

20
21
22
- Reducing costs to consumers by proactively adapting to market conditions, reallocating risk, and taking advantage of historically low interest rates or costs of capital.

1   Q   **HOW CAN APS'S RATES BE MORE COMPETITIVE BASED ON THE SPECIFIC**

2   **ITEMS MENTIONED IN THIS PARTICULAR ISSUE RAISED BY COMMISSIONER**

3   **PETERSON?**

4   A   Commissioner Peterson's objective of achieving more competitive retail rates can take

5   a big step toward doing so through changes made in the particular items mentioned by

6   Commissioner Peterson on this particular issue. Equity capital is the most expensive

7   form of capital for two reasons: (1) because of its subordinated nature in the event of

8   default relative to debt, it is inherently riskier and requires a premium in excess of the

9   cost of debt; and (2) it has tax consequences that increase the revenue requirement

10   for ratepayers which is calculated by the tax gross-up, or revenue conversion factor.

11   By proactively adapting to current market conditions, the Company could issue

12   incremental debt during today's current low-cost environment and move its capital

13   structure and equity ratio to a more balanced level. Doing so would reduce the revenue

14   requirement by lowering the return on rate base, as well as reducing the cash taxes

15   paid by customers in rates.

16   Another avenue that can be used to ensure APS's rates are competitive would

17   be to adopt a more competitive ROE. The Company's initial and updated ROE

18   requests of 10.15% and 10.00%, respectively, significantly exceed the current market

19   cost of equity capital for the reasons presented in my Direct testimony and this

20   surrebuttal testimony. Further, the Company's requested ROE is well in excess of

21   authorized ROEs on a national level by a significant margin. This is even more

22   apparent when compared to the four states identified by Commissioner Peterson in her

23   letter to the parties.[26] For example, the authorized ROE in the four states identified by

---

[26]Commissioner Peterson identified Washington, Oklahoma, Texas and Virginia as states she wanted APS's rates to become more competitive with.

1   Commissioner Peterson have been in the range of 9.20% to 9.42% in 2019 and 2020.

2   I have summarized this in Table 2 below.

TABLE 2

Average ROE

State	Year	
	2019	2020
Oklahoma	9.40	-
Texas	-	9.42
Virginia	-	9.20
Washington	-	9.40

S&P Global Market Intelligence

3

4   This compares to the Company's requested ROE of 10.0% in this proceeding

5   and my recommendation of 9.3%. The spread becomes even wider after accounting

6   for the FVI. Notably, none of the four states identified in Commissioner Peterson's

7   Letter allow for an additional FVI to the rate of return that I am aware.

8   **Q   DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?**

9   A   Yes, it does.

Arizona Public Service Company

Projected and Actual Interest Rates 1st Quarter 2002 - 1st Quarter 2020

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.819420812
R Square	0.671450467
Adjusted R Square	0.666823009
Standard Error	0.569619136
Observations	73

ANOVA

	df	SS	MS	F	Significance F
Regression	1	47.08045111	47.0805	145.101	7.90205E-19
Residual	71	23.03708314	0.32447		
Total	72	70.11753425			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	-0.395724696	0.360223487	-1.09855	0.27567	-1.11398993	0.322540538
Projected	0.908869789	0.075451162	12.0458	7.9E-19	0.758424446	1.059315133